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ASSESSMENT OF THE QUALITY AND SUPPLY LIMITS OF CONVENTIONAL TRANSPORTATION FUELS

Prepared by:
R.F. Webb Corporation Ltd.
1011/5 Prince of Wales Drive
Ottawa, Ontario K2C 3K1

For:
Energy Planning Directorate
Transport Canada
Ottawa

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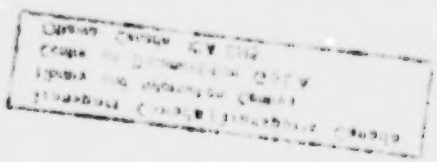

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NOTE ON THE REPORT

This report is meant to serve as a simple introduction and overview to a complex and rapidly changing subject, and as an interpretation of the future transport fuel position in Canada as seen, at this time, by the contractor.

The contents of the report reflect the views of the contractor and not necessarily the views or policies of the Energy Planning Directorate of Transport Canada.

Draft copies of the report were kindly reviewed by groups at the department of Energy, Mines and Resources, the National Research Council and the Transport Development Centre and certain of the changes suggested have been incorporated, but the errors and omissions are those of the contractor alone.

SUMMARY

The report presents a view of the oil supplies available to Canadian refiners to the year 2000 and changes in the anticipated supply, demand and quality of transport fuels.

In the most likely scenario domestic production of oil will not be adequate to meet demand in 1990 and the gap between supply and demand (estimated optimistically at the 70,000 m^3/day level, or pessimistically at the 100,000 m^3/day level in 1990) must be filled by imports and alternative fuels which are not based on oil. While vigorous action now could close the supply/demand gap by 2000, it is likely that imports will still be necessary (at 27,000 m^3/day to 120,000 m^3/day levels, depending upon the amount of investment undertaken). Assuming Hibernia oil becomes commercial by 1990, oil imports into Ontario may account for 30-54% of the requirements of Ontario's refineries, while Quebec's dependence on imported oil will increase from the 1980 level of 44% of supplies to a 75%, or even 95+%, dependence by 1990. In this scenario imports into the Atlantic region will increasingly be displaced by Hibernia product; Alberta and Saskatchewan crudes will continue to meet the needs of the western provinces; but exports to eastern Canada and the U.S. (principally heavy oil) are expected to decline. The changes in the origin of crudes to eastern refineries will affect the yield and quality of transport fuels available in the future, as will reduced demand for gasoline and fuel oils for heating purposes.

Major changes are forecast in refinery operations in the period to 2000, due to a decreased demand for gasoline and a decrease in the ratio of leaded to unleaded gasoline. The effect of a phase-out in the use of lead in gasoline, if legislated, would require large investments and refinery changes. In the case where lead use is continued, the reduced future demand for gasoline (except in the west) can be met without octane degradation by increased severity of reformer operations and conversion of gases from the cracking of heavier stocks to polymer gasoline and octane-boosting alkylate. The operation of polymer and alkylate units

will convert light by-products from cracking to useful products.

Highway diesel and jet fuel demand is expected to increase sharply. The demand can be met readily in the Atlantic refineries from high grade Hibernia crude, but with difficulty elsewhere, and a relaxation in specifications and/or investments to upgrade low quality distillates to transport fuel grades is anticipated. Rail, marine and stationary engine use of diesel fuel will also increase, but these applications can utilize lower ignition quality fuels, such as those diverted from heating oil use. Changes in the cost of transport distillates relative to gasoline are likely in response to increased distillate upgrading costs and increased demand, the shrinkage of heating fuel markets which now act as a sink for low quality distillates, and a relative abundance of gasoline, particularly of the low octane components of gasoline.

New refinery capacity will be required in the west, much of which will incorporate facilities for the upgrading of low quality distillates to transport diesel fuel. East of Saskatchewan the current surplus refining capacity is expected to become worse and further closing out of refining capacity and certain small refineries is foreseen, although perhaps ameliorated somewhat in Newfoundland, should the export of finished product from the processing of Hibernia crude be permitted.

The report contains an analysis of transport fuel quality and supply in a scenario (which emphasises the highway and air modes) where Canada is regarded as four refining regions, each supplied by a given slate of domestic and/or foreign crude oil to meet a forecast level of demand. Other scenarios investigated earlier by the National Energy Board and by the Montreal Engineering Company for Transport Canada are briefly reported. A note is provided on the possible adoption of propane, compressed natural gas and alcohols as transport fuels in the period to 2000: it being estimated that these fuels could provide between 5-8% of transport fuel requirements by 1990 and between 8 and 15.5% by the year 2000. Given that domestic oil production could be stimulated to the level corresponding to the optimistic supply scenario of this report, alternative fuels appear to

be capable of closing the supply/demand gap, even by 1990, but the impact of these fuels (which are essentially gasoline substitutes) at the levels required to close the gap on refinery operations, has not been investigated.

INTRODUCTION

This report forms part of a series of investigations of strategic planning related to transport fuels. This part deals with factors which may affect the supply and quality of conventional fuels based on oil.

The report builds upon an earlier study conducted for Transport Canada by Montreal Engineering Company Ltd. (hereafter "Monenco"), which included the development of simple models to represent clustered refineries in each of four regions in Canada: the western provinces, Ontario, Quebec and the Atlantic provinces. The models have been updated to include the effects of production of various grades of leaded and unleaded gasoline and recently-announced refinery expansions, and incorporate the latest forecasts on crude oil supply of domestic and foreign origin, and domestic tar sands syncrudes. Large uncertainties in domestic oil production remain, however. Great changes in the demand forecasts for individual and total transport fuels have also occurred since the January 1980 starting date of the original Monenco investigation, due to the price effects of the National Energy Program and the Canada/Alberta Energy Pricing and Taxation Agreement, small vehicle purchases and the recession, all of which have contributed to a greater-than-expected reduction in the demand for oil and transport fuels.

In view of the wide variations in domestic oil production capacity (the NEB forecast, for example, ranges from a low of 144,000 m^3/day and a high of 204,000 m^3/day in 1990 to a range of 92,500 m^3/day to 370,000 m^3/day in 2000), with small variations in forecasts of oil and fuel demand over the period 1980-2000, we have chosen a most likely case for oil supply and petroleum product demand for analysis, followed by the examination of variants, including the cases originally specified to Monenco for its study. Since all forecasts of future demand and supply are certain to be wrong in detail, the present analysis aims not to make volume forecasts, but rather to identify trends and constraints to the supply and quality of transport fuels in each region to the year 2000, including the adequacy of the refining complexes in place, or announced.

The report examines in PART 1 the world and Canadian oil production prospects, the level of Canadian demand for oil and transport fuels and the allocation of crudes to the four regions. The gap between domestic supply of oil in each region is determined and the need for oil imports, deep local conservation, or alternative non-petroleum fuels, assessed. In PART 2 the crude oils available to each region are then considered for their suitability as feedstock to the refineries and the impact of the refinery equipment, or processing limitations on the supply of transport fuels and/or their specifications are addressed. The effect of variations in quality of fuel, of a restricted supply of oil and of a high demand for diesel fuel are examined.

In PART 3 the influence of large use of alternative transport fuels, such as methanol and propane, is touched upon, but no detailed investigation is presented here, nor is one available from other sources on the impact at the refinery of large-scale adoption of these gasoline substitutes.

The effect of engine developments, legislated (or voluntary) fuel economy standards, legislated emission levels and the limits placed on the use of lead in gasoline, on the use and availability of certain grades of transport fuel, are also examined.

These elements of the 3-part investigation conform to the statement of work prepared for the project, which is given in full in the Appendix. Also included in the Appendix are the Monenco report and the details of the more recent refinery simulations conducted for the contractor by Padgett Process Services Ltd.

PART 1: CRUDE OIL SUPPLY/DEMAND

1. OIL SUPPLY PROSPECTS

1.1 Free World Supplies

There is a surplus of oil production capacity at the world level, but the bulk of that capacity and the reserves which support it are no longer under the control of the major oil companies of the west and the stability in price and supply they exercised in the past has been lost. The increased volatility of demand, prices and supply have made the oil planning process more difficult and more critical. It is, therefore, imperative that nations like Canada seek to establish an increased independence from foreign supply and to diversify the sources of that oil which must be purchased abroad until self-sufficiency, which is within our future grasp, can be obtained.

As shown in Table 1, some 58% of oil production capacity in the non-communist world is within the OPEC cartel, which is itself centred on the Arab OPEC group (OAPEC). Saudi Arabia has exercised its production strength in recent years: first by producing close to its short-term maximum production rate of 12 million BPD to hold prices down, and more recently to the 6.5 million BPD level to hold prices up, as other producers sought to gain a larger share of the current curtailed market through price cuts. Non-OPEC production from Canada, Alaska, the North Sea, Mexico, and perhaps non-OPEC African sources, is expected to expand to reduce OPEC's share of the "free world" market somewhat (to 48% by 1985 ?), but OAPEC reserves are such that they must continue to dominate the free world supply of oil throughout the remainder of the century.

The ratio of oil reserves to production ($^{R}/_{P}$) is the usual measure taken of the gross adequacy of oil supply and reflects the number of years of future supplies available from proven oil reserves. In the late 1950's there was an oil glut when the ratio exceded 40 years of supply at the then current rate of use. With North Sea and large Mexican additions and improved African prospects, the $^{R}/_{P}$ ratio for the non-communist nations

Table 1

1981-2 SOURCES OF CRUDE OIL (FREE WORLD)

Millions BPD

	Capacity	Forecast of Production, 1982
OPEC		
Saudi Arabia	11.0	7.5
Iran	3.0	3.2
Iraq	4.0	
Kuwait	2.5	1.1
Nigeria	2.4	1.9
Libya	1.4	1.3
Other OPEC	8.7	7.5
Subtotal	33.0	22.5
NON-OPEC		
CANADA	1.5	1.2
U.S.A	17.9	8.4
Mexico		2.7
North Sea		2.4
Others	4.9	4.7
Subtotal	24.3	19.4
TOTAL OIL	57.3	41.9
Total Gas Liquids	4.9	4.9
Total Oil & Gas Liquids		46.8

Estimated Free World demand Oil and Gas Liquids:

Winter 1981-2 period	50.3 million BPD
Summer	46.4 million BPD
1982 Average	46.8 million BPD

Source: Oil Week, Dec. 7, 1981, p. 70: revised by Webb, June 1982

in the 1980's will be close to 36 years of forward supply; new discoveries will roll this supply horizon forward for many years, but ultimately the reserves will diminish. There is considerable controversy on the timing of the downturn in R - the reserve, or inventory component, and on the rate of growth in demand for oil which controls P - the production component. A problem with the OPEC dominance is that P, the production component, can be held low for political and long-term OPEC economic reasons, whereas in the pre-1973 era, P was controlled solely by market demand.

1.2 The Canadian Potential for Oil Production

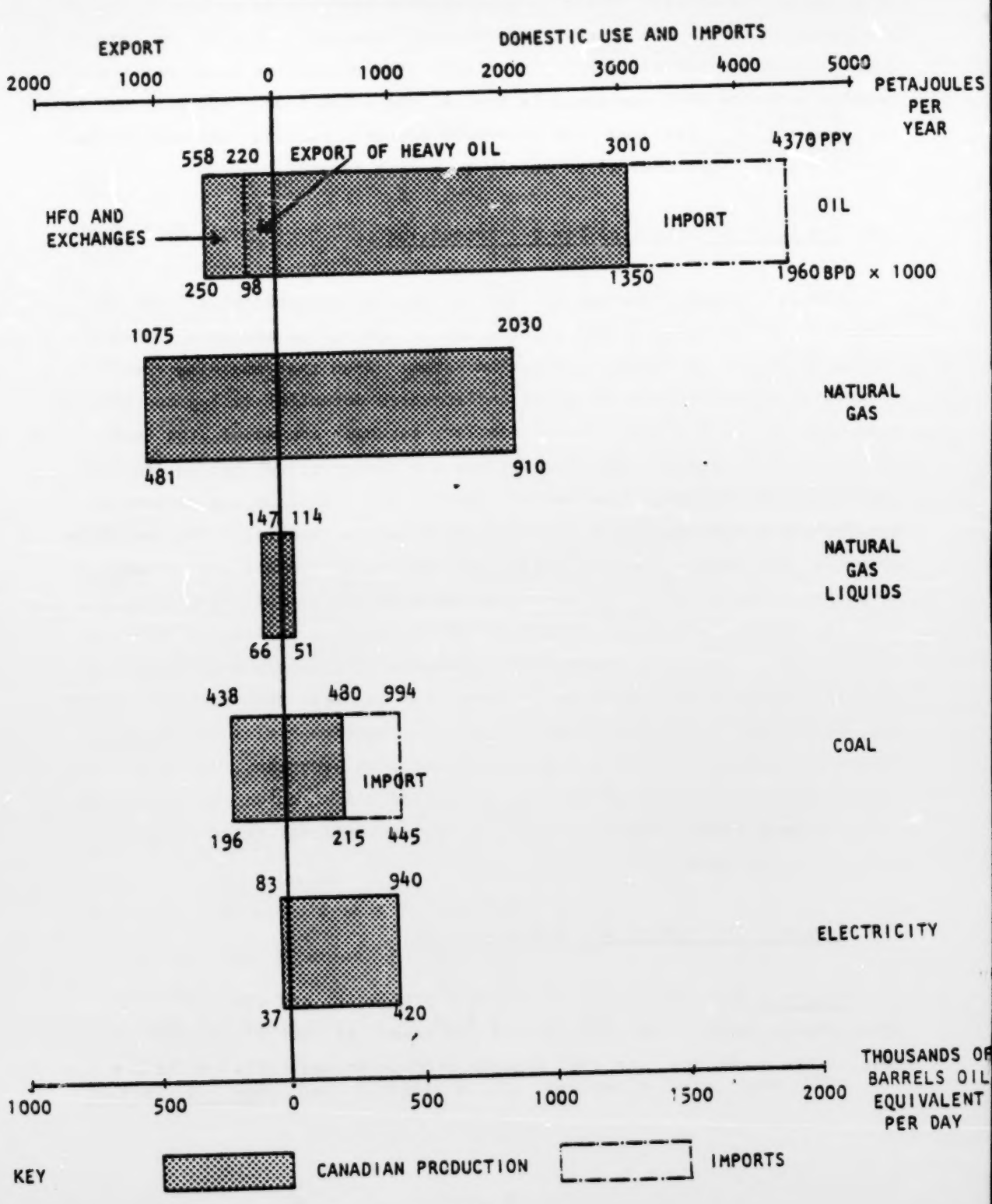
Canada's proven reserves of light-to-medium conventional oil and gas liquids were estimated by EMR and the NEB in 1980 to be adequate for only 10 years' supply at current production rates. When the remaining reserves, discovered resources and estimated undiscovered potential (using conventional practices with 50% probability of recovery assumed) are added, the supply (R/P) stretches to 30 years. The calculations are conservative, but do include contributions, not only from western Canada, but also from the Mackenzie-Beaufort area, the eastern Arctic and the Hibernia deposits. The long-term potential for Canada lies in finding new sources of conventional crude, complemented by enhanced recovery from depleted wells, but predominantly from the intractible heavy oil and oil sands deposits in Alberta and Saskatchewan. Including these in the potential oil supply provides a resource adequate for the country's needs for at least 200 years and probably 400, at present production rates. Thus, the long-term limits to Canada's future oil supply lie not with geology, nor with geography, but with the economics of oil production and the quality of oil which can be wrung from these unconventional resources. Meanwhile, conventional reserves are at a critically low level.

1.3 Canada's Oil Imports and Energy Balance

Figure 1 provides a view of Canada's production and use of oil and other energy forms. The 1980 numbers are taken, as 1981 oil production results are anomalous: in 1981 Alberta production was curtailed before

Figure 1

CANADIAN ENERGY BALANCE 1980 (EXCLUDES BIOMASS USE)



completion of the Canada-Alberta Energy Pricing and Taxation Agreement in September 1981 and output of synthetic crude oil was reduced, due to operating problems of the Suncor and Syncrude processing plants.

As shown in Figure 1, Canada imports only oil among its net energy requirements and the potential exists, not only for new oil production from tar sands and heavy oil, but, if necessary, for use of a huge natural gas, coal and electricity base, together with the gas liquids available from natural gas processing, to replace oil directly with these energy sources, or indirectly through their conversion to synthetic fuels.

The oil balance for Canada includes not only importation of 30% of the requirements of the nation's refineries (imports were 102,600 m^3/day in 1981; 98,000 m^3/day in 1980), but the incongruity of oil exports in the form of finished products and heavy oil (33,770 m^3/day in 1981; 31,000 m^3/day in 1980). That is, imports are at the 600,000 BPD level; exports are one third of that. The heavy oil is from two sources: a 'natural' variety, produced predominantly at Lloydminster in Saskatchewan and a 'residual' variety, which represents the bottom of the barrel from many Canadian refineries. Both of these resources are exported because no facilities exist in Canada for their processing to conventional petroleum products: such refining facilities exist in a number of U.S. refineries. There is an opportunity to use these heavy oils and residuals to replace conventional crude oil as the Alberta production declines from the 150,000 m^3/day level to the 100,000 m^3/day level in the early to mid-1990's from unconventional wells, but large new investments in upgrader facilities are required: decisions to proceed with these investments do not appear to be imminent.

Notwithstanding the existence of some 8,000 m^3/day of heavy oil being shut in for lack of processing capability and export markets, and 40,000 m^3/day of conventional oil also shut in as the temporary aftermath of supply arrangements made during the 1981 production curtailment ordered by the government of Alberta, the major problem for Canada's refineries is the availability of domestically produced oil. The supply shortfall will be

overcome by imports, which brings another set of problems related to the surety of supply, and the declining quality of imported feedstocks, the price of which have increased 20-fold since 1970 (see Table 2).

1.4 Domestic Sources of Oil

1.4.1 Domestic Resources of Conventional Light-to-Medium Oil

Domestic production of conventional light and medium oil will continue to decline at a 5% annual rate, or higher, providing only 800-850,000 BPD (130,000 m^3/day) production by 1990 and 650,000 (100,000 m^3/day) by 1995 from these resources, predominantly in Alberta.

The new oil reference price (NORP) established in the Canada/Alberta Energy Pricing Agreement has effectively doubled the price of new oil in 1982 (to $41.65 per barrel) compared to 1981 and a return to the former 500 or so drilling rig level is expected to produce these forecasted supplies when this opportunity percolates through to the equity capital market. The most promising areas for development are reported to lie in the Sheklie, Southern Alberta, Pembina and Golden fields.

1.4.2 Tertiary Recovery Processes

Tertiary recovery processes will be implemented to provide a modestly increased supply of light-to-medium oil, with an increasing proportion of heavy crudes recovered later. A study entitled Enhanced Oil Recovery Potential in Canada, issued in 1980 by the Canadian Energy Research Institute, gives estimates for the oil recovery potential from this source and various technologies in the range of 1.5 to 6.3 billion barrels from a 35 billion barrel resource. The extent of recovery is dependent not only upon prevailing and anticipated prices for oil, but upon further demonstrations of tertiary recovery technologies which include: steam drive; in-situ combustion; polymer augmented-, microemulsion- and alkaline water flood methods; hydrocarbon and carbon dioxide miscible-flood methods.

Table 2

HISTORIC AND PROJECTED PRICES FOR OIL

($/BBL Basis)

	Imported Oil	Conventional Oil	Blended Price	Blended Price as % of World Price
1970	2.25	2.63	2.63	117
1974	12.78	5.83	5.83	46
1980	39.53	15.58	16.96	43

	Imported (new oil) at Montreal	Old oil at Montreal	Federal Levies	Blended Price	Blended Price as % of World Price
1981	43.90	20.27	7.81	28.08	64.0
1982	48.96	26.17	9.52	35.69	72.9
1983	51.09	33.44	8.41	41.85	82.0
1984	55.73	41.61	7.85	46.49	88.8
1985	60.20	45.15	9.17	54.32	90.3
1986	64.64	48.48	10.73	59.21	91.6

Sources: Canadian Enerdata on historic; Alberta Petroleum Marketing Commission forecasts

Taking the light oil (API gravity 25°+) potential using tertiary recovery methods, the National Energy Board estimates a technical total recovery of 527 million m^3 (3.3 billion barrels) of which some 30% could be recovered at an incentive price of \$189/m^3 (\$30/bbl), 57% at an incentive price of \$239/m^3 (\$38/bbl) and 69% at an incentive price of \$300/m^3 (\$47.60/bbl).

The rate at which the recovery of light crude oil by tertiary recovery methods can be implemented is expected to be dependent on the price, but in any case slow development is forecast due to the lead times required for project design, regulatory approvals and construction and industry apprehension concerning the supply and cost of injection fluids. The annual supply potential by 1985 was gauged by the NEB to range from 2000-4000 m^3/day in 1985 to 3000 (low incentive) to 20,000+ m^3/day (with world price applying) by 1990.

A likely supply scenario for light crude oil by enhanced recovery techniques, considering investment and technology restraint, and the NORP price, is:

1985 production	3,000 m^3/day	(19,000 BPD)
1990	13,000 m^3/day	(82,000 BPD)
1995	18,000 m^3/day	(113,000 BPD)
2000	20,000 m^3/day	(126,000 BPD)

The light-to-medium gravity crude oil recovered by enhanced techniques presents no refining problems not normally encountered with conventional light-to-medium gravity domestic crude oil.

1.4.3 Heavy Oil Production and Upgrading

The rate of exploitation of the massive heavy oil resources of Canada is constrained, not by the identification of the location of the resources,

but by technical and financial constraints which limit the quantity lifted by conventional and enhanced recovery techniques and the timing of that recovery, and also by two downstream factors: the lack of suitable upgrading facilities in Canada; and in the export market the price of Canadian heavy oil may be too high while a choice exists to purchase Canadian, indigenous and off-shore (Mexican, Venezuelan and Arabian) heavy crude supplies and higher quality crude.

The National Energy Board estimates for the supply of heavy crude oil range from a 1981 low of 31,400 m^3/day, to a 1990 low of 36,000 and a 1990 high of 65,800 m^3/day, to a low of 23,700 m^3/day and a high of 53,800 m^3/day by 2000 - the supply level determined by the available market and price. At least until 1990 the supply potential exceeds domestic refining ability. In 1980, 15,000 m^3/day of heavy oil were exported and further development of this resource may require not only upgraders in Canada, but continuation of the export market to stimulate resource recovery and production investment in Canada (and a seasonal cushion of supply). Exports could also help to stimulate investments in novel tertiary recovery schemes which could provide additional supplies of heavy oil comparable in volume to that from the application of enhanced recovery techniques to light-to-medium crudes. A technical potential of 667 million m^3 of heavy oil is available, which could in time be tapped to the 50, 30 or 15% level, depending upon price and the investments made in upgraders. The availability of heavy oil is therefore not the determining factor: the downstream investments made to upgrade heavy oil will determine the exploitation rate.

The upgrading of heavy oil was supported in the NEP by incentive grants to cover 10-20% of approved costs, depending upon the level of Canadian ownership, and price incentives (with due adjustments for quality) for new production were recognized in subsequent pricing agreements and were revised upward. At least 10,000 m^3/day of additional heavy oil production could be added within 6-7 years, if projects were supported to increase Saskatchewan production by 50%. The upgraded portion is assumed available for domestic use.

The upgrading project that is most advanced is the so-called "Saskatchewan upgrader" joint venture between Husky Oil (25%), Saskatchewan Oil and Gas Corp. (Saskoil,25%), Gulf Canada Resources (20%), Petro-Canada (15%) and Shell Canada Resources (15%) which, as originally planned, involved an investment of $1.5 billion. The upgrader may be uneconomic under today's investment conditions and implementation is uncertain. With the pressure to curtail imports, it is expected that some means will be found to implement the upgrader by 1995.

Similar costs and considerations apply to the plan to upgrade heavy fuel oil residues from a pool of refineries in Montreal in a new facility which would be owned by the Carmont consortium of refiners headed by Gulf Canada Ltd. A plan to process between 8,000 m^3 and 16,000 m^3/day of residuals produced in Montreal is still under consideration, but may falter.

The $2 billion price tag for the 15,000 m^3/day facility and the expectation of lower future prices for imported oil may be responsible for the current investigation of lower processing levels - 6,000 m^3/day - and for the lack of decisions to proceeed. An additional factor is that, with reliance placed upon Hibernia and imports for future supplies to Quebec, the need for residual processing may be less than originally forecast. Petro-Canada, a participant in the Carmont group, is proceeding with a 5,000 BPD (800 m^3/day or so) hydrocracking pilot plant (based upon EMR's CANMET laboratory process) to evaluate residuals upgrading, and this process may be applied to tar sands bitumens in due course. Ultramar, at St. Romauld, Quebec, is proceeding with its own residual upgrader, which it estimates will cut oil intake to the refinery by 50% to 4,750 m^3/day, when the installation of the 2,400 m^3/day residual upgrading capacity is complete.

For the purposes of the forecast of supply, recognizing the pressure to reduce imports, particularly to Ontario and Quebec, and to use the heavy oil and residual oil surplus, the following implementation schedule appears probable:

	m^3/day			
	1985	1990	1995	2000
Residual processing				
St. Romauld	2000	2500	2500	2500
Other Montreal	800	800	6000	6000
Ontario	-	-	2500	2500
Total residual refining	2800	3300	11000	11000
Heavy oil Saskatchewan upgrader	-	-	10000	15000

While upgrading investments and the production level will be determined by market factors, government suasion will be required. It is to be noted that the residual fuel upgrading is a necessary import conservation measure, which increases the yield of premium products per barrel processed: syncrudes, of course, do not produce residuals for upgrading, since the bottoms have already been removed in the bitumen coking operations. A future move to bitumen hydrocracking technologies, such as the CANMET process being investigated by Petro-Canada, would require added residual oil upgrading capacity. This could use capacity which might become obsolete, if large volumes of high quality frontier oil become available. Such obsolescence is the major hold-back to the Montreal upgrader decision; permission to import heavy oil to continue its use when Hibernia oil is available is being sought.

Use of natural 'heavy oil' increases total supply; the residual oil upgraders will reduce the requirement for imports. In addition to these benefits of oil volume, upgraders will improve the quality and value of the total oil pool, since their processing will provide a reduction in the sulphur level and increase the average API gravity of oil processed. The volume of distillates which may be obtained from the total domestic oil pool will increase at the expense of unwanted heavy fuel oil fractions.

1.4.4 Syncrude Production from Oil Sands

The tar sands and heavy oil deposits in Canada lie in four major formations in northern Alberta, the best known and largest of which are the

Athabasca tar sands, the other deposits being known as Wabasca, Peace River and Cold Lake. In total, these deposits contain oil in place currently estimated at over 200 billion m^3 - over twice the level of total conventional world oil reserves. Synthetic crudes are currently produced by the mining of tar sands, separation and coking of the extracted bitumen material at two plants (Suncor and Syncrude) with a combined design capacity of 24,000 m^3/day (155,000 BPD) - 10% of Canadian crude production.

Engineering work has been conducted on expansion of the Syncrude plant to provide, by the mid 1980's, a total of 38,000 m^3/day (240,000 BPD), on a second mining project (Alsands) and on an in-situ recovery operation (Cold Lake), each of which could add a further 21,500-22,000 m^3/day (135,000 to 140,000 BPD) of syncrude capacity when fully operational. Other mining and in-situ prospects have also been studied.

The Syncrude expansion now appears unlikely. The Alsands consortium has recently been dismantled and the Cold Lake in-situ project was deferred earlier. Even with vigorous efforts to rekindle engineering and investment interest, no new syncrude plant is likely to be on stream before 1992-4, and it is possible that investment in the future will be in smaller plants than those proposed for Alsands and Cold Lake. The burden of a $100,000 investment per daily barrel of syncrude production (on an as-spent basis) must be overcome. Changes in the processing technologies, including the recovery of synthetic gas liquids now used as fuel, could make an important contribution to cost reduction.

Firm forecasts of oil sands production by 1995 and beyond are not possible, and we must await a technical, or economic break-through, or some international oil crisis to change the present investment attitude. No additions to syncrudes from these sources are therefore included or scheduled in the forecast given in this report.

The syncrude contribution to Canada's oil supply will remain essentially at the current level to 1990,with minor allowance made for debottlenecking and increased throughput in the two existing plants. After 1990, an optimistic view would be that the equivalent of one Cold Lake or Alsands plant would be added by 1995, another by 2000; a pessimistic view would be that the equivalent of not more than one new plant would be placed in production and with the current plants refurbished, or replaced by similar capacity, to continue that supply.

Given these possibilities, syncrude production would be as follows:

	$m^3 \times 1{,}000$/day			
	1985	1990	1995	2000
Optimistic	23	33	55	75
Pessimistic	20	24	24	45

(Note that the syncrude output in 1981 averaged only 17,500 m^3/day, due to plant problems, down from the 1980 level of 20,300 m^3/day).

1.4.5 Frontier Oil

The major prospect for the future supply of high quality (high API gravity, low sulphur) oil compatible with a simple refinery operation, lies in development of the Hibernia deposits off Newfoundland, where opportunity for high quality (31°API) is offset by technical problems (iceberg infestation in the area, the depth of the ocean), economic problems related to the technical risks involved, and unresolved political problems.

The Mackenzie Delta-Beaufort Sea and Arctic Island discoveries together provide a larger ultimate oil potential than Hibernia, but large-scale exploitation of these resources appears unlikely before the mid-1990's. Accordingly, the oil supply estimates used in this study assume frontier production being initiated at Hibernia by 1986, with total frontier

production (essentially all Hibernia) reaching a 40,000 m^3/day (250,000 BPD) level by 1990 (the level at which investments and Hibernia production would be justified). The level may be optimistic, being somewhat higher than that forecast for the frontier by the NEB (36,000 m^3/day) in its 1981 report in the highest of its crude oil production forecasts. The larger number is taken, in view of recent agreements by Exxon and Dome to expand drilling efforts in these areas.

After 1990, production results are expected from the increased level of exploration. An optimistic and speculative forecast of supply from the frontier sources is as follows:

	m^3/day			
	1985	1990	1995	2000
Hibernia	-	40,000	45,000	45,000
Arctic, Mackenzie Delta, Beaufort Sea	-	3,000	15,000	50,000
Total		43,000	60,000	95,000

1.4.6 Pentanes Plus

The processing of natural gas at gas plants provides supplies of light gases and liquids, such as ethane, propane and butane, and other valued liquids of higher molecular weight, "pentanes plus", which are used in refineries to augment crude oil supply. (Certain gas deposits also produce quantities of much heavier fractions, termed "condensate", which may be the source of naphtha and aromatics). Some 16,900 m^3/day of penatanes plus were recovered by gas plants in 1981, 97% of which originated in Alberta.

In the future, increased quantities of pentanes plus may be used in enhanced recovery schemes and the NEB and oil companies forecast a modest increase in total production of pentanes plus in line with increased gas volumes to 1984 (to 17,700 m^3/day) and thereafter a decrease, due to

reduced gas exports, termination of major gas cycling schemes and a gradual decline in the pentanes plus content of gas from older fields and from gases dissolved in oil (solution gas).

The pentanes plus supply position forecasts are (NEB Report, Canadian Energy Supply and Demand: 1980-2000):

	1981	(1984)	1990	1995	2000
m^3/day (rounded)	17,000	(18,000)	17,000	11,000	9,000

The pentanes plus fractions are included in the conventional light and medium oil fractions shown in the forecasts of Canada oil supplies given in Table 3. The contribution of the LPG component of natural gas is discussed in Part 3.

1.4.7 A Summary of Oil Supply and Demand 1985-2000: A Current View

Two scenarios of oil supply for the period 1985-2000 are given in Table 3. In the optimistic case, the decline in conventional oil production by conventional and enhanced recovery programs is offset by Hibernia supplies, with large supplies of other frontier oil coming on stream after 1990. The forecasts beyond 1990 are speculative: investment decisions have yet to be made to win the new resources envisaged.

The outcome of the two supply scenarios is compared to the demand forecast in Part 2.

The supply scenarios presented in Table 3 show that, in the optimistic case, domestic production of oil and equivalent in 1985 is expected to be only 86% of 1981's depressed level and 78% of the highest 1980 production level. Even in the optimistic scenario, the production level of 244,000 m^3/day achieved in 1980 will not be reached again until about 1992. The pessimistic scenario indicates that the potential exists that, after a decline to 1985, no significant addition to total oil production volumes

Table 3

OIL SUPPLY SCENARIOS (INCLUDES PENTANES PLUS)

(Thousand m^3/day)

	1985	1990	1995	2000
OPTIMISTIC CASE			**SPECULATIVE**	
Conventional oil & pentanes plus	130	102	80	60
Tertiary recovery, light, medium oil	3	8	18	20
Tarsands syncrudes	23	33	55	75
Heavy oil	34	41	40	32
Hibernia	-	40	45	45
Other frontier	-	3	15	50
Total production	190	227	253	282
Less exports of heavy oil	15	21	10	6
Net production	175	206	243	276
Residuals and product exports	13	10	0	0
Net available production	162	196	243	276
PESSIMISTIC CASE				
Conventional oil & pentanes plus*	130	95	68	48
Tertiary recovery	2	5	10	15
Tarsands syncrudes	20	24	24	45
Heavy Oil	30	36	31	25
Hibernia	-	30	40	42
Other frontier	-	-	2	15
Total production	182	190	175	190
Less exports of heavy oil	15	16	8	0
Net production	167	174	167	190
Residuals and product exports	12	10	7	5
Net available production	155	164	160	185

* 7% annual decrease after 1985

would be available throughout the remainder of the century. Even darker prospects can be envisaged, if domestic use of heavy oil does not increase as anticipated in the scenarios.

The prospects sketched in the scenarios in Table 3 reflect a deterioration of production prospects seen from a 1982 perspective compared to those foreseen in 1980 when the National Energy Program was developed and supply cases provided to Monenco for their study. The changes in the production prospects for 1990 compared to the NEP are mainly:

1. Production of syncrude from the oil sands will be reduced.
2. Heavy oil upgrading is delayed.
3. The goal of oil self-sufficiency by 1990 may be unattainable unless three important contributions are rapidly brought forward: greatly expedited frontier oil (Hibernia) implementation; the role of alternative non-petroleum fuels is greatly expanded; new measures are taken to conserve liquid fuel use.

1.4.8 Regional Distribution of the Domestic Supply

The logistics and economics of oil transport indicate that the domestic sources in Alberta and off-shore Newfoundland will be used first to satisfy demand in their regions, with the surplus shipped by the most economic means (pipeline) to adjacent provinces, with imports filling the gap.

The changes in the pattern of oil transportation in the period to 1990 are significant: imports into the Atlantic provinces will be replaced by off-shore supplies, the volume of Alberta oil moving east will decline sharply, with the result that Ontario's refineries will become major users of foreign oil and Quebec refineries will likely increase their dependence on imports. The extent of these imports is dependent upon the oil supply-demand gap, which is examined next.

2. OIL DEMAND AND CANADA'S PRODUCTION GAP

2.1 Free World Oil Demand

The resolve with which oil conservation is practiced and the search for new sources of oil and oil substitutes pursued in Canada bear a direct relationship to the availability and cost of foreign oil, which is itself dependent upon the balance between supply and demand in the non-communist world. The current free world capacity for oil and gas liquids production has been given as 62 million BPD in a period when winter demand reaches 50.3 million BPD and summer demand 46.4 million BPD.

Texaco Inc., in its recent forecasts of the future demand for petroleum products in the non-communist world, given in Table 4, forecasts a rise in the total average demand from a 1980 level of 48 million BPD to a level in the year 2000 of 60 million BPD, under the circumstance that the real price of Arab light crude oil will increase at a 1 to 2% annual rate. The 22% increase in total demand by 2000 will require a substantial increase in production capacity to meet seasonal and cyclical peaks in demand and large effort to ensure the replacement of depleting reserves.

The Texaco forecast of free world demand for petroleum products is compared in Table 4 to that forecast for Canada in the same period and was derived from an averaging process applied to Canadian oil company forecasts provided in submissions before the NEB 'All Energy Hearings' in 1981.

The forecast for Canada is qualitatively similar to that for the rest of the world, with a total increase in consumption of petroleum products: large increases are forecast for jet fuel and diesel fuel, for petrochemicals and other non-fuel uses. A sharp reduction in demand for residual fuel is also forecast, due primarily to its conversion to lighter products and vulnerability to replacement by alternatives, such as gas and coal. The Canadian demand for gasoline is forecast to decline in absolute terms, whereas the demand for gasoline outside Canada (and particularly in the developing world) will increase modestly in the next 20 years.

Table 4

(a) FREE WORLD DEMAND FOR PETROLEUM PRODUCTS 1980-2000

	Thousands BPD 1980	Thousands BPD 2000	Thousands m^3/day 1980	Thousands m^3/day 2000	% Increase (decrease) 1980-2000
Motor gasoline	12,500	12,700	2,000	2,020	+1.6
Jet fuel	2,200	3,700	350	600	+68
Diesel and heating oils	11,300	16,600	1,800	2,600	+45
Residual fuel	11,500	9,800	1,800	1,550	(-15)
Petrochemicals, other	11,500	17,000	1,800	2,700	+48
Total	49,000	59,800	7,750	9,470	+22 (Average)

(b) CANADIAN DEMAND FOR PETROLEUM PRODUCTS 1980-2000

Motor gasoline	688	585	109	93	(-15)
Jet fuel	81.5	167.5	13	26.5	+105
Diesel and heating oils	525	673	83	107	+28
Residual fuel	251	126	40	20	(-50)
Petrochemicals, other	284.5	358.5	45	57	+26
Total	1,830	1,910	290	303.5	+4.4 (Average)

Sources: (a) Free World demand: Texaco, 1981

(b) Canadian demand: R.F. Webb Corp. investigation of oil company briefs to NEB, 1981.

Comparison of world and Canadian demand leads to the following conclusions:

1. Residual fuels and heavy oils will be difficult to market.
2. Distillate growth throughout the free world for jet fuel, diesel fuel (and perhaps light heating oils) will put pressure on supplies of light crude oil.
3. A gasoline export market for Canada might be developed.
4. Total demand will press hard upon the existing production capacity for oil.
5. Refinery configuration changes will be required, not only in Canada, but elsewhere to meet the changed pattern of fuel demand.
6. The refinery changes required in Canada reflected by the change in the gasoline-to-distillate (G/D) ratio from 1.1 in 1980 to 0.7 in 2000 will be larger than the world average, where the gasoline-to-distillate ratio will change from 0.93 in 1980 to 0.63 in 2000. The G/D ratio in both Canada and the free world is constrained by economics, as transport fuel costs rise sharply when distillates production exceeds 40% of the total of gasoline and distillates.

2.2 The Supply/Demand Gap

The demand for liquid fuels to 2000 derived from forecasts of all the major suppliers in Canada, shown in Figure 2, indicates the growth of demand for transport fuels. The decrease in total petroleum product demand, which reaches a minimum in 1990, is attributed principally to the replacement of heating oils by electricity and natural gas engendered by 'off-oil' programs and projects, such as the extension of natural gas supplies to Quebec and the Atlantic provinces through the TQ and M pipeline now under construction. The changing composition of the fuels required will be investigated later. For the moment, concentrating on the supply gap that will exist between demand and domestic oil production, shown in Table 5, it is noted that the pessimistic case means that the level of imports of oil into Canada would essentially be unchanged over the twenty year period, with imports by 2000 being 118,000 m^3/day. The optimistic case shows that the gap could be reduced by 1990 to the 70,000 m^3/day level and by 1995 to the 30,000 m^3/day

Table 5

OIL SUPPLY/DEMAND PROJECTIONS

(Thousand m^3/day)

OPTIMISTIC SUPPLY CASE

	1985	1990	1995	2000
Demand (1)	275	265	275	303
Available supply (2) (3)	162	196	243	276
Shortfall (Imports and/or alternative fuels)	113	69	32	27
Shortfall in BPD x 1000, rounded	710	435	200	170

PESSIMISTIC SUPPLY CASE

Demand	275	265	275	303
Available supply	155	164	160	185
Shortfall (Imports and/or alternative fuels)	120	101	115	118
Shortfall in BPD x 1000, rounded	755	635	725	745

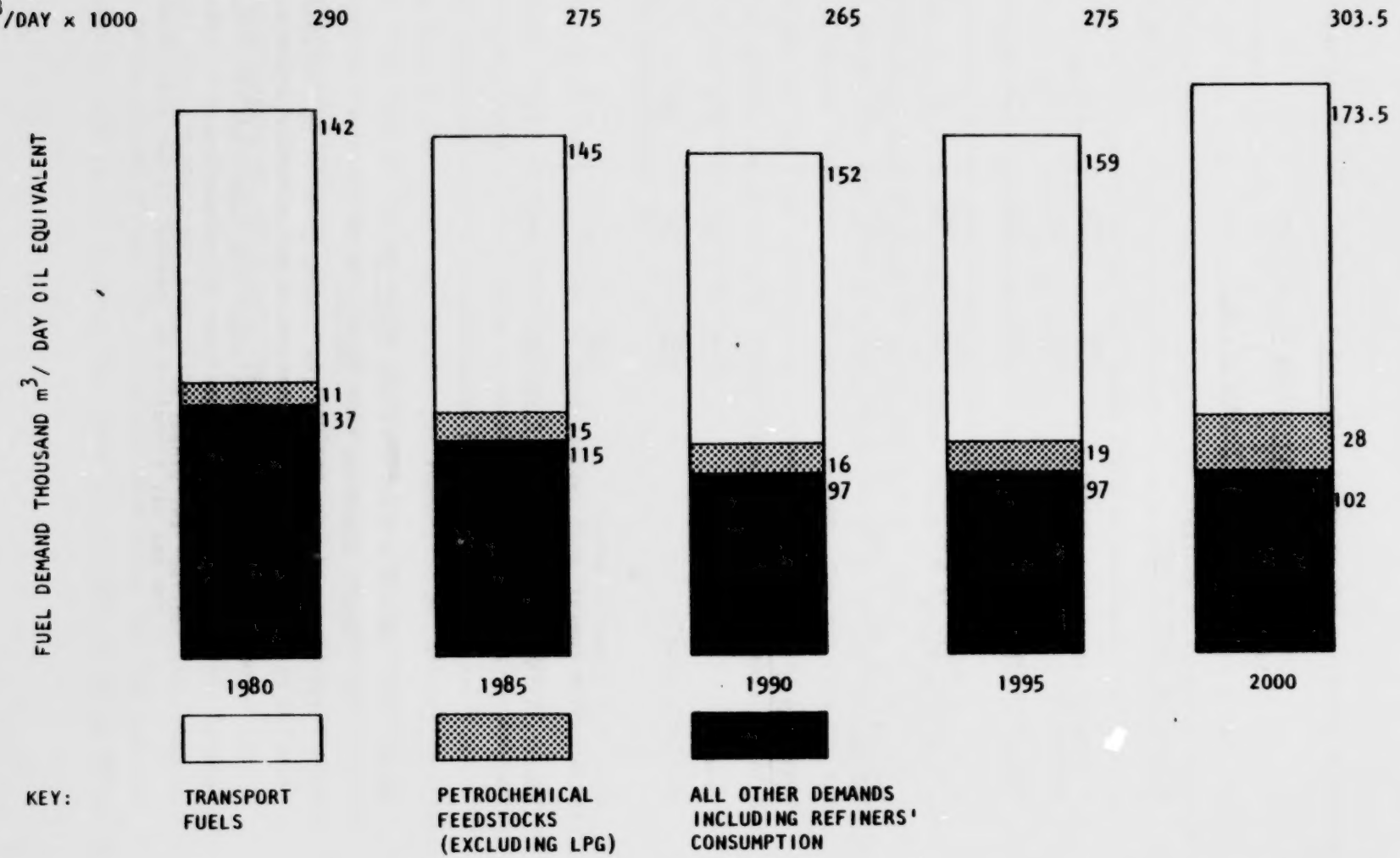
Notes: (1) Demand projections, see Figure 2.

(2) Supply scenarios from Table 3, p.18.

(3) The projections take the liberty of equating finished product demand volumes with the equivalent volume of crude oil. This is considered sufficiently valid for the present supply/demand gap analysis when both supply and demand are volatile and difficult to forecast, even in the short term to 1985. The effect is to underestimate the crude oil requirement - the gap may therefore be somewhat larger than shown.

Figure 2

CANADIAN LIQUID FUEL DEMAND 1980-2000 (EXCLUDES LPG)



level which assumes: Hibernia production is initiated by 1990, a heavy oil upgrader in operation before 1995, and further tar and syncrude investments made and in operation.

Given the optimistic supply scenario, the import gap is small enough to be capable of being closed by aggressive use of alternative fuels; in the pessimistic case the need for alternatives is even more urgent, but it is unlikely that the vehicle, fuel distribution and other changes required to take advantage of the alternatives can be put in place to completely close the serious gap that may occur in the pessimistic supply situation.

2.3 Regional Oil Supply/Demand

Taking the year 1990 and expanding the supply/demand data from the national to the regional level, it may been from Table 6 and Figure 3 that the oil shortfall in both the optimistic and pessimistic supply cases falls upon Ontario and even more heavily upon Quebec, while the Atlantic region swings from 100% reliance upon imported crude to total reliance upon Hibernia (and possibly other frontier sources) by 1990 or so, and that the western region maintains its ability to produce at a rate surplus to its burgeoning demand.

The change in Quebec will be from reliance on imported crude for 43.6% of supply in 1980 to either a 75% dependence, or a 96-97% dependence by 1990, with the change that, in 1980, domestic supply (56.4% of requirements in the province) was from western Canada; in 1990 such domestic supply as will be available must come from Hibernia and other frontier production, after the requirement of Atlantic refineries has been met.

The change in Ontario is from reliance in 1980 upon western crudes for 90% and U.S. exchanges for 9.5% of refinery feedstocks and a small quantity from eastern Canada (0.5%) to the point where imported crudes will constitute 30% to 54% of refinery feedstocks. Overall for Canada the optimistic scenario suggests that imports which in 1980 were 32.3% of refinery requirements may decrease to 26% by 1990, but are just as likely to follow the less attractive

Table 6

REGIONAL OIL ALLOCATION: 1990

(Thousand m^3/day)

OPTIMISTIC SUPPLY CASE

	Prairies & B.C.	Ontario	Quebec	Atlantic Provinces	Total Canada
Conventional (1)	65	45	-	-	110
Net heavy crude oil (2)	13	7	-	-	20
Syncrude	28	5	-	-	33
Frontier	-	-	15	28	43
Domestic Supply	106	57	15	28	206
Imports	-	25	44	-	69
Exports (3)	(3)	(3)	(3)	(1)	(10)
Net domestic supply/ demand	103	79	56	27	265
Exports (4)	24	3	3	1	31
Total Demand	127	82	59	28	296

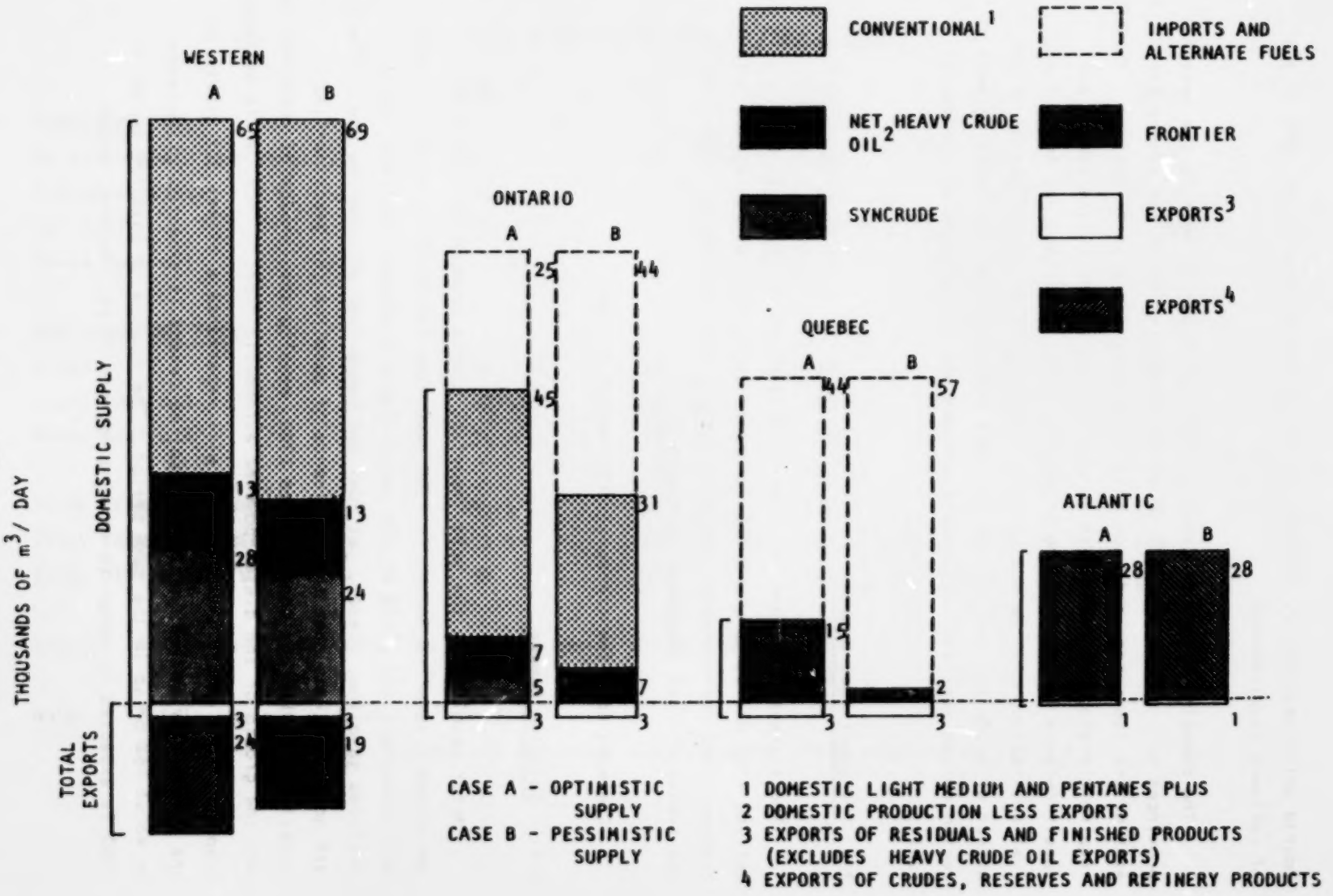
PESSIMISTIC SUPPLY CASE

Conventional (1)	69	31	-	-	100
Net heavy crude oil (2)	13	7	-	-	20
Syncrude	24	-	-	-	24
Frontier	-	-	2	28	30
Domestic supply	106	38	2	28	174
Imports	-	44	44	-	101
Exports (3)	(3)	(3)	(3)	(1)	(10)
Net domestic supply/ demand	103	79	56	27	265
Exports (4)	19	3	3	1	26
Total Demand	122	82	59	28	291

Notes:
(1) Domestic light, medium oil and pentanes plus
(2) Domestic production, less exports
(3) Exports of residuals and finished products (excludes heavy crude oil exports)
(4) Exports of crudes, residuals and refinery products

Figure 3

REGIONAL OIL ALLOCATION 1990



CASE A - OPTIMISTIC SUPPLY

CASE B - PESSIMISTIC SUPPLY

1 DOMESTIC LIGHT MEDIUM AND PENTANES PLUS
2 DOMESTIC PRODUCTION LESS EXPORTS
3 EXPORTS OF RESIDUALS AND FINISHED PRODUCTS (EXCLUDES HEAVY CRUDE OIL EXPORTS)
4 EXPORTS OF CRUDES, RESERVES AND REFINERY PRODUCTS

course which requires an increase in the volume of imports by 1990 to 35% of refinery requirements.

The changing origin of Canadian refinery supplies outside the western provinces will effect the ability of refineries to match the demand for each of the fuels required, not only in volume, but also in quality. This inquiry therefore proceeds with an examination of the future demand and specifications for each of the principal fuels (gasoline, jet fuel, diesel fuel and heating oil) before turning in Part 2 to an investigation of the effect of crude oil quality and refinery configuration available in each region on the availability, specifications and performance of transport fuels.

2.4 Transport Fuel Demand

The aggregated demand for liquid fuels given in Figure 2, p.24, derived from oil company and NEB forecasts is further disaggregated into transport and non-transport fuels in Table 7 and into the oil input for the transport fuel component in Figure 4.

Comments upon the transport fuel demand follow.

2.4.1 Gasoline Demand

Motor gasoline is the most important single product derived from petroleum: gasoline demand in 1980 accounted for 33.5% of total refinery oil throughput and 68.5% of the total liquid transport fuel pool which includes gasoline, diesel, jet fuel and heavy fuel oil (marine use). There are no indications that this dominance of gasoline (or gasoline-like substitutes) will not continue to 2000, despite the inroads of conservation and the growth of the diesel-powered automobile fleet. Thus, while national transport fuel demand (see Table 7) will experience a modest 20% growth in the twenty-year period, national gasoline demand is expected to decrease by about 15% or so in the same period. The decline in gasoline volume by 2000 is expected to occur to varying degrees in all regions, except

Table 7

FUEL DEMAND 1980-2000 (m^3/day x 1000)

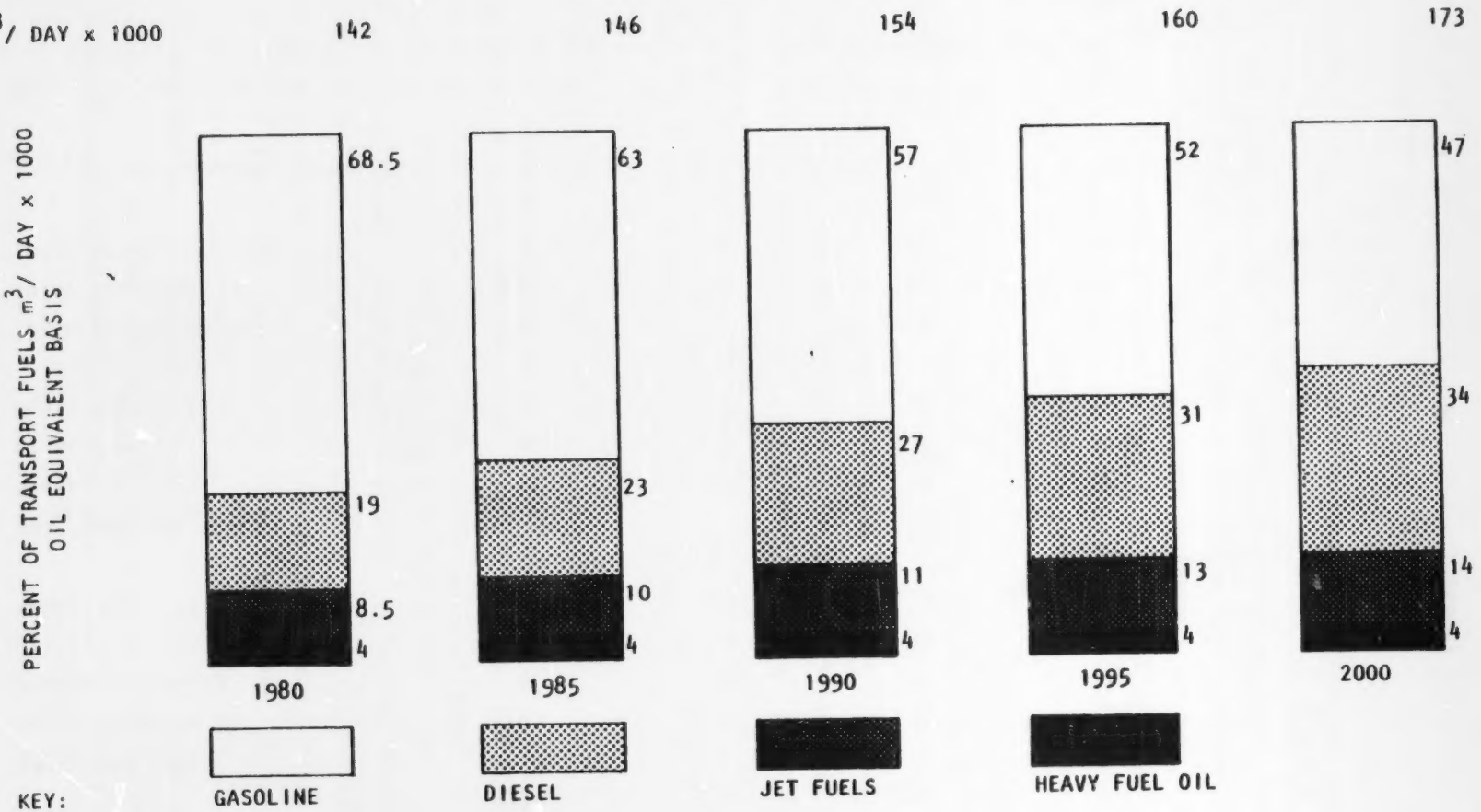
	1980	1985	1990	1995	2000
TRANSPORT FUELS					
Gasoline (Auto and aviation)	109	105	99	94	93
Transport diesel	26	33	41	49.5	57
Jet fuel	13	16	18	22	26.5
Heavy fuel oil	4.5	5	5	6	6.5
NON-TRANSPORT FUELS					
Diesel	15	18	22	26	31
Light fuel oil	42.5	33	26	21	19
Heavy fuel oil	35	28	19	14	13.5
TOTAL PETROLEUM FUELS	245.5	237	230	233	246
TOTAL TRANSPORT FUELS	152.5	158	163	171.5	183
TOTAL DISTILLATE FUELS	96	98	107	120	133

Source: Oil company submissions to National Energy Board, 1981

Note: Totals may not add, due to rounding.
Excludes asphalt, petrochemicals and other non-transport products given in Table 4

Figure 4

OIL DEMAND FOR TRANSPORT FUELS 1980-2000



NOTE: OIL VOLUMES DIFFER FROM FUEL VOLUMES GIVEN IN Table 7 REFLECTING DIFFERENT GRAVITY OF FUELS AND REFINERY LOSSES

Alberta and the Territories, whereas the combined demand for all transport fuels is expected to grow in every region except Quebec.

The key factors affecting the demand for gasoline in the next twenty years are the effect of fuel economy standards (currently voluntary and at the vehicle manufacturer level in Canada), the level of public demand for more fuel-efficient automobiles and light vans driven by the increasing price of gasoline, and a modest reduction in annual miles travelled per vehicle, offset by the expected growth of the nation's road vehicle population from the current level of 13 million to 15.5 to 16 million by 1990 and about 19 million by the year 2000.

The drive for fuel economy in automobiles will be met by further downsizing of vehicles to increase the level of compacts and subcompacts to 50% of the fleet by 1990, the use of smaller engines with fewer cylinders and the further development of aerodynamic vehicle designs, engine/transmission system matching and changes in driving practices. The changes in combustion systems include the development of high compression engines and turbocharged engines, and microprocessor-controlled fuel delivery, timing and other operating features to deliver the optimum balance between fuel consumption and emission controls.

The move to fuel-efficient engines will accelerate the penetration of diesel engines into the new car market, thus replacing gasoline consumption by a lower level of consumption of diesel fuel: diesels are about 25% more efficient than gasoline engines in automobiles on a volume basis due to the nature of the diesel combustion process and the higher BTU content of a volume of diesel fuel compared to gasoline. The diesel advantage is achieved, however, at substantially increased engine cost and may be reduced sharply when a new generation of high-compression spark ignition engines with direct fuel injection and electronic combustion controls (such as those now being introduced by Porsche) become available. The effect of a large increase in the demand for automotive quality diesel fuel on refinery operations is discussed in Part 2.

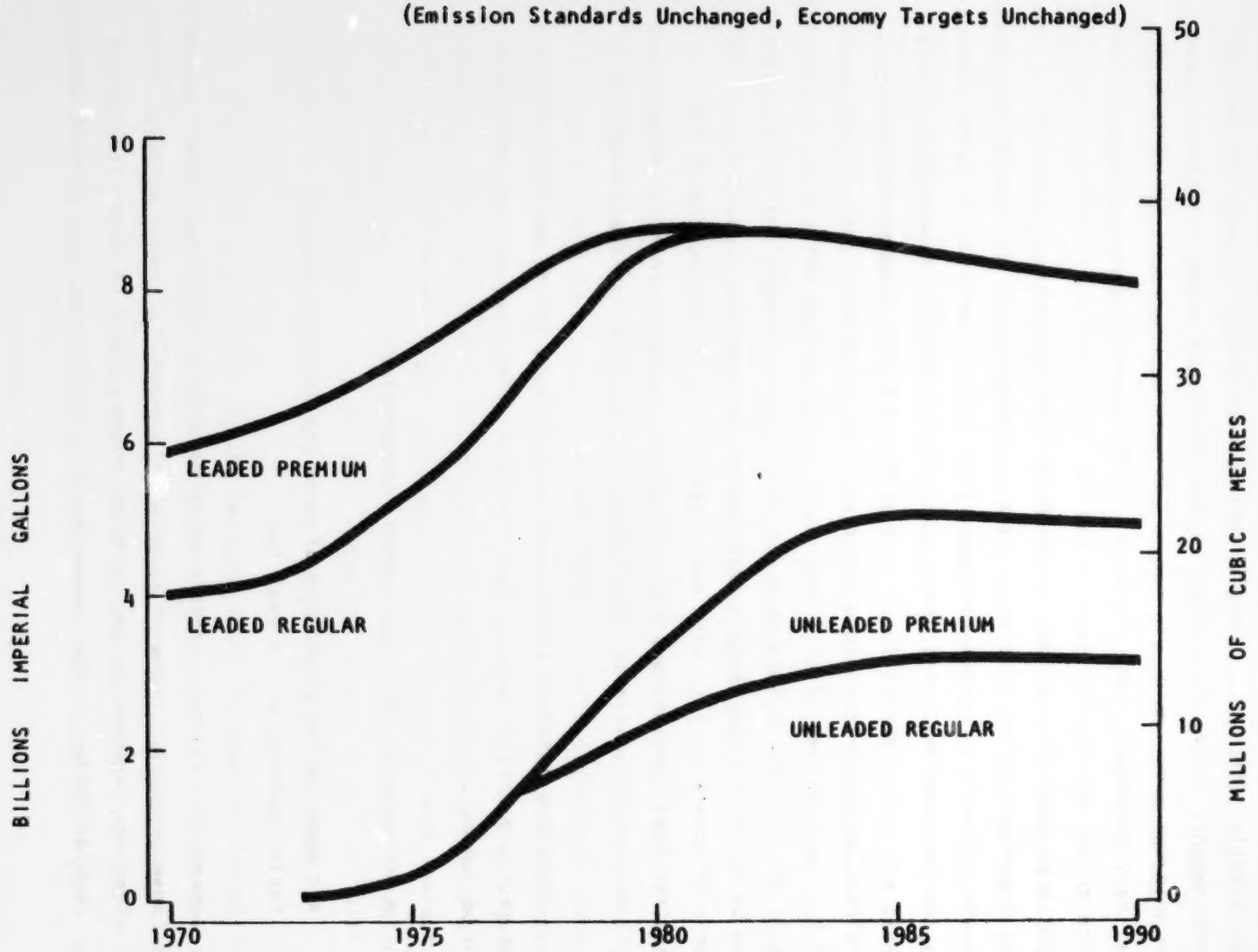
The higher fuel economy possible with high compression gasoline engines will require the maintenance or increase in the octane value of gasoline - an increase in the proportion of premium to regular sold. This is to be accomplished in a period when the use of lead additives, which provide an inexpensive route to octane improvement, are being phased out in response to two areas of regulation. In the first, the permissible lead levels in gasoline are almost certain to be further reduced; despite the current 'holding action' in Canada. Second, U.S. vehicle emission control legislation has led to the vehicle manufacturer's development and commercialization of rare metal-containing catalyst systems which are incompatible with leaded fuel - the catalysts are deactivated by lead. While Canadian legislation does not require emission control at the level which necessitates the use of 3-way catalyst systems, designs and many of our vehicles originate in Detroit and the number of vehicles in use which can use only unleaded fuel is increasing and the average lead level of 0.4g/litre now in use is lower than the maximum permitted level of 0.77g of lead/litre.

Unleaded gasolines comprise only 40% of automotive gasoline sales in Canada at the moment, but the proportion is changing. The total elimination of lead, which may eventually occur, requires either a reduction in the octane rating of gasolines with increases in fuel use (due to the lower combustion efficiency of low octane fuels), or measures to be taken in the refinery to increase the octane level of gasoline blending stocks. The increased use of octane boosting additives, such as alkylate, is currently limited by their availability, but could be increased sharply if investments were made in the recovery of olefins from coking operations (such as the future tar sands plants and current syncrude plant cokers), in the production of isobutane (used in the production of alkylate), or of new octane improvers, such as methyl-t-butyl ether (MTBE, produced from isobutylene and methanol). The use of MTBE may not yet be economic in Canada, but is used in Europe and the U.S. Ethyl Corporation's view of these gasoline trends is summarized in Figure 5.

Figure 5

GASOLINE SALES OUTLOOK

(Emission Standards Unchanged, Economy Targets Unchanged)



Source: Data from Ethyl Corporation

New spark ignition engines are under development which are insensitive to the octane value of the fuel, or have a low octane requirement. The stratified charge engines are not expected to appear in number in the period to 2000 and even if numbers do join the vehicle fleet after 1990, they will not greatly affect the slowly changing total fleet, or gasoline quality requirements before 1995-2000. Thus high octane values will be required in unleaded gasoline in the future and will be achieved by a balance of refinery processes - an increase in the severity of cracking operations with an oil consumption penalty and the increased use of non-metallic octane boosters, part of which may be produced from natural gas, rather than from oil dependent refinery streams. The increased use of oil and/or gas streams in the refinery to produce unleaded high octane fuels may be largely offset by the improved fuel efficiency achieved in the vehicle when high octane fuels are used - particularly if a trend to higher compression ratio engines can match the octane increase. An increase in road octane number of 4 in a gasoline, if utilized, would increase fuel efficiency by 1 to 1.5%. It is of interest to note that electronic knock sensors and controls are now being built into certain gasoline engines to permit operation at the limit of octane quality with optimized control of engine timing and required fuel consumption; this is often termed "electronic octane" and will be a major source of improved gasoline economy in the future.

There are numerous other items which affect future gasoline demand and gasoline specifications, but the major effects at the refinery level can be summarized as follows:

- a decrease in the total demand for gasoline

- a change in the proportion of gasoline required to other transport fuels, particularly diesel fuel

- changes in refinery operations to provide higher octane clear (unleaded) base gasoline (increased severity of reforming, installation of isomerization) required by the changing proportion of unleaded premium and regular grades to the leaded varieties (additives such as MTBE may assist).

2.4.2 Diesel Fuel Demand

Diesel fuel is a major and fast growing component of Canada's liquid fuel mix. Diesel fuel demand in 1980 totalled about 260,000 barrels per day (41,300 m^3/day: NEB estimate), 60% of which was used in the transport sector (road 35%; rail 18%; marine 7%), in mining, other industrial and farm use (34%) and for electric power generation and in off-highway equipment.

The largest area of growth for diesel fuel lies in transportation. Fleet fuel economy standards can be most easily met at the manufacturers' level by the inclusion of diesel engines in the fleet mix (fuel economy standards are on a volumetric, not a calorific basis). The performance of small high speed diesel engines (noise reduction, faster acceleration, faster cold start) has been greatly improved in recent designs and manufacture. The operating cost savings (principally fuel) and added range offset the higher price of the diesel ($400-700 premium in automobiles). The use of diesel in commercial fleets is increasing also.

Heavy duty (Class 7 and 8) trucks with gross vehicle weight in excess of 26,000 lbs. (truck and carrying capacity) are essentially completely dieselized at this time, but all other trucks and even light duty commercial delivery vans are being dieselized. This can be seen in the appearance of European and Japanese manufactured trucks on the road, and arrangements made by N. American truck manufacturers to import vehicles and/or engines for Class 6 and lower weight vehicles. Most of the bus fleets (except school buses and local feeder buses) in N. America are already dieselized and expansion of bus travel (in both urban and intercity service) will increase as automobile operating costs and gasoline prices rise.

The use of diesel fuel on the railways will increase only modestly as heavy freight movements expand in line with the growth of the economy and especially of Canada's resource (mineral, oil, coal, forest products)-based industries. Many of these industries also consume diesel fuel within their operations in earth moving, mining equipment, heavy duty off-highway vehicles

and in on-site electric power production; consumption will also grow with the further development of resource-based industry and the northern territories.

Increased activity in marine transport is also expected and certain of the smaller vessels in this service consume high grade diesel fuel, others with heavier, slow speed 'cathedral' engines used in intercontinental transport vessels, consume heavy fuel oil ('bunker C') which is not included in the diesel fuel category. Certain large-scale diesel electric power plants also consume heavy fuel oil, the diesel engine being an alternative to steam turbines in the conversion of heavy fuel oil to electricity or marine motive power.

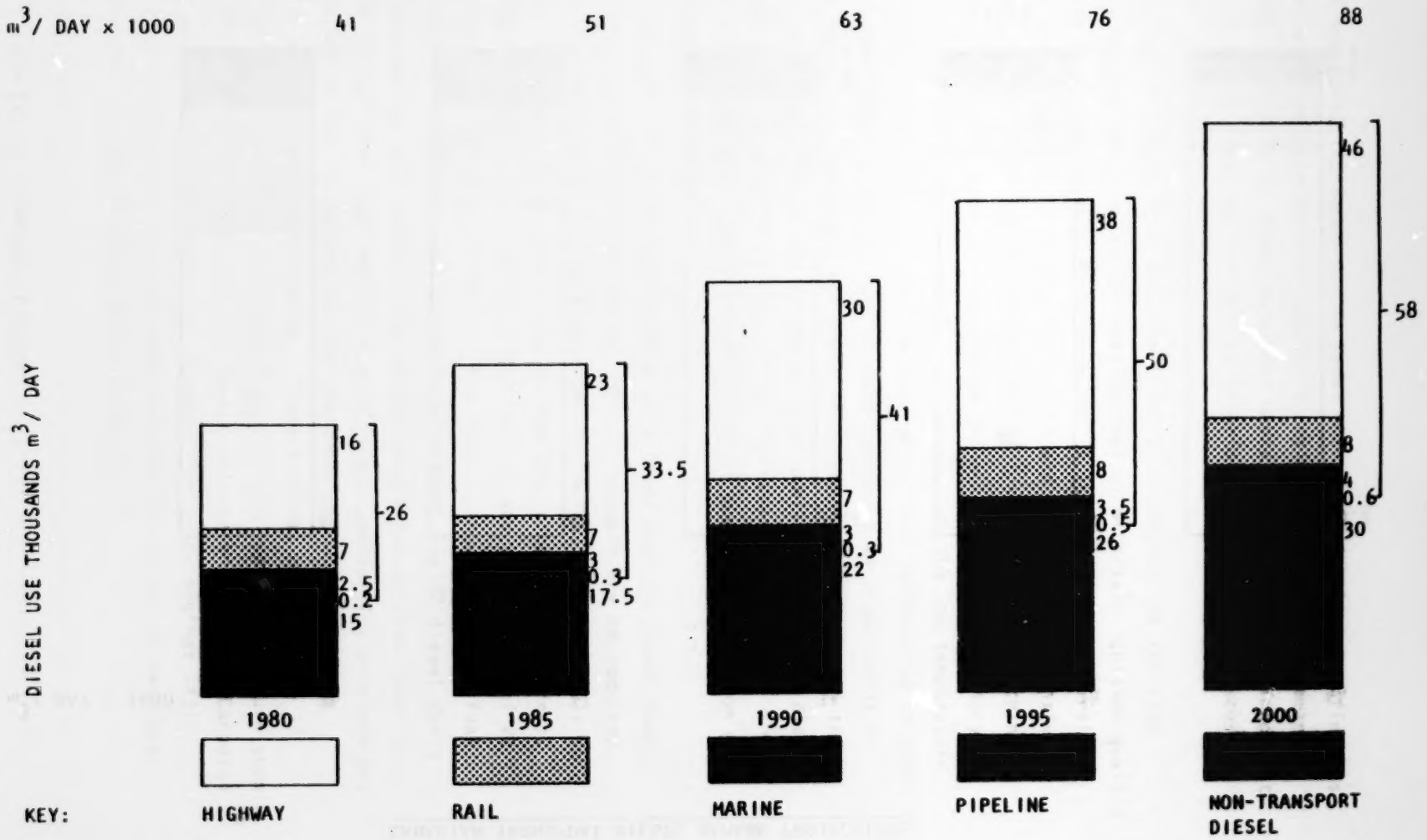
In their submission to the NEB energy hearings, the oil companies' views of diesel growth in the transport sector were in substantial agreement, but forecasts of the growth of diesel fuel use in the non-transport applications differ widely. Our own view, shown in Figure 6, is that non-transport demand for diesel will double in the 20 year period, unless sharp price changes occur to offset the advantages that diesel fuel has of high safety (high flash point), high energy density/unit volume (low transport and storage cost), high efficiency of combustion in high compression engines and the wide tolerance of non-automotive diesels to fuel quality degradation.

Our expectation of total growth of diesel fuel in the transport sector is in the 4% per annum range, resulting in a doubling of the use of diesel from the 1980 level by 1995. As shown in Figure 7, growth in the highway use predominates.

The changing demand for diesel fuel and the high rate of growth of automotive and truck use will exacerbate the diesel fuel supply problem and fuel quality which already exists in the western provinces. The problem will be compounded in the future by the changing chemistry of crude oils used in Canada as the proportion of tar sands and heavy oil

Figure 6

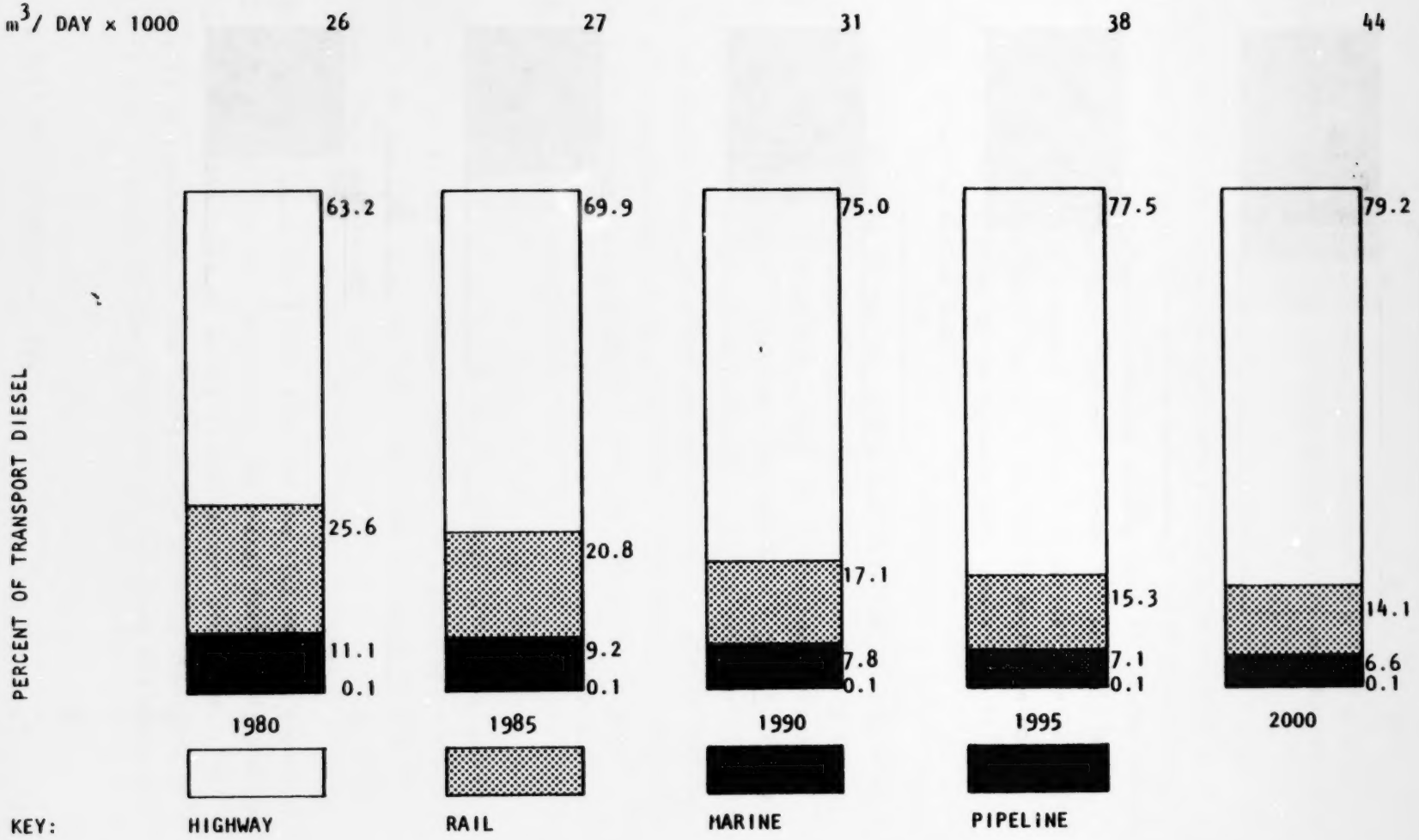
CANADIAN DIESEL FUEL DEMAND PROJECTIONS



NOTE: TOTALS MAY NOT ADD DUE TO ROUNDING

Figure 7

CANADIAN TRANSPORT DIESEL DEMAND PROJECTIONS



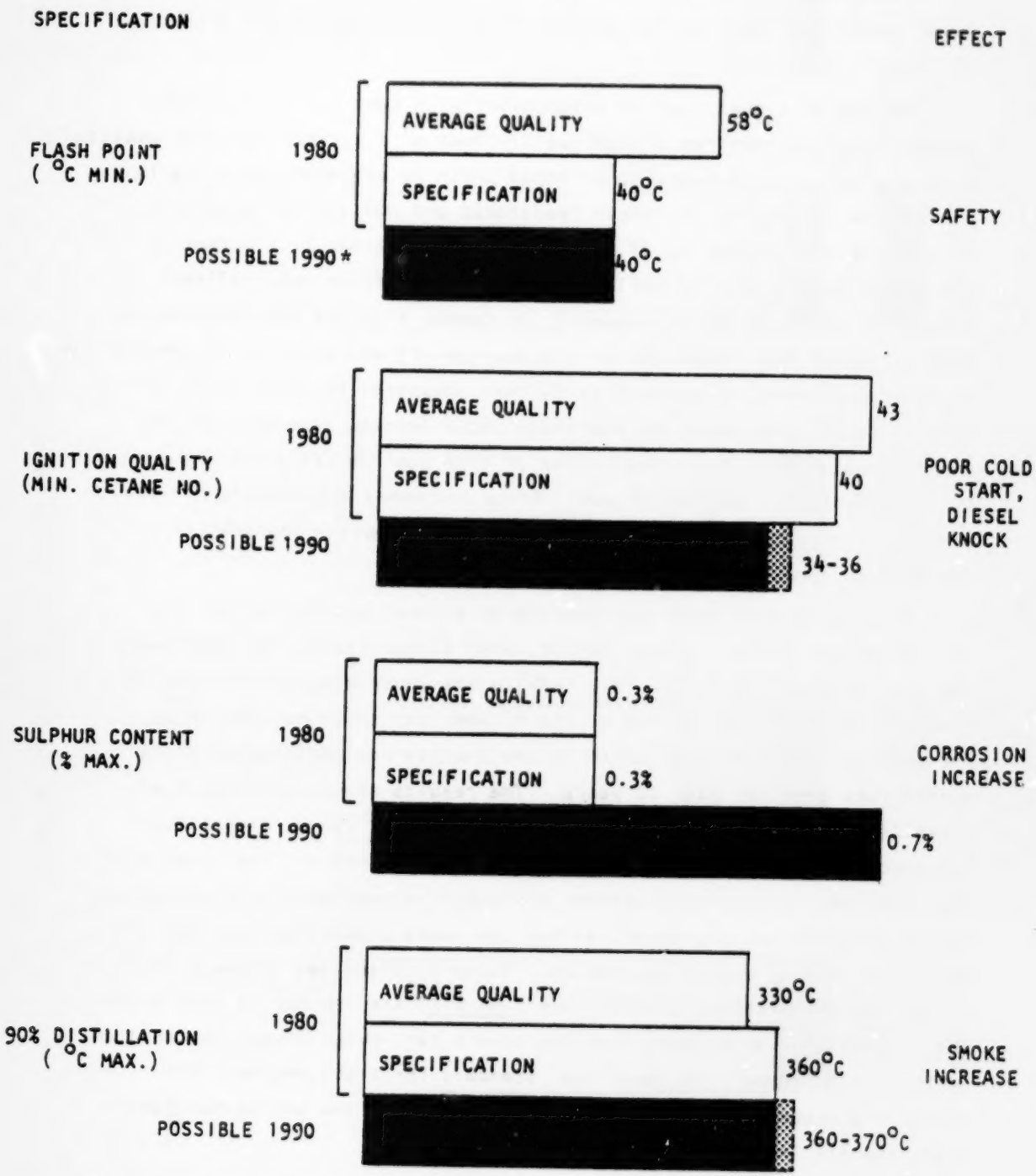
derived syncrudes increases to the level where certain Alberta refineries will be based entirely on syncrudes (in a region where the peak demand for diesel fuel will be experienced) and where syncrudes will be important in refineries at least as far east as Ontario. See Part 2 for discussion of this.

The use of diesel fuel in automobiles with compression ignition (diesel) engines requires a high quality fuel of a certain ignition quality or cetane value (preferably 50 or more) which is achieved economically only in the processing of virgin feedstocks and not through extensive degradation and processing of higher boiling fractions (i.e. cracking and hydrotreating of high boiling vacuum gas oil fractions, refinery bottoms or residuals and bitumens). In Canada also, the low temperature pourability of fuel (measured by the pour point) and tendency to crystallize at low temperature clogging fuel filters (measured by cloud point or related tests), are important and these requirements, coupled with the cetane requirement, limit the volume of high quality (#1 diesel) diesel fuel available for automobile use. Price increases may constrain diesel growth, since increased supply and avoidance of quality degradation will require new investments.

Trucks and most buses can operate on a lower quality diesel fuel (#2) except in certain winter months, when #1 quality may be required. The quality requirements for this service are increasingly difficult to meet. A recent survey by one of the N. American truck manufacturers, for example, shows a major shift in the quality and performance of #2 diesel fuel over the past 10 years. The results showed that the fuel cleanliness (particulate levels) had deteriorated, the #2 diesel fuels had become heavier and waxier; the cetane levels had drifted lower with the total result that cold weather startability, operability problems and filter plugging had increased, as had the smoke production and the variation in fuel quality by region. These problems may increase if grades now being tested by CGSB (see Figure 8) are typical of future supply. Due to the Canadian climate they may have a particular impact on Canadian vehicle performance. (A lower fuel standard for truck engines (#3) recently proposed in the U.S. has been rejected by the engine manufacturers and the American Trucking Association).

Figure 8

DIESEL FUEL SPECIFICATIONS AND 1980 AVERAGE QUALITY



Note: * POSSIBLE 1990= Fuel grade under test by CGSB to set 1990 standards.
Current and Tentative specifications from CGSB.
1980 quality data from Gulf Oil.

The major thrusts in truck and bus diesel engine design being conducted by the engine manufacturers are aimed at improving the fuel economy of diesel engines without reduction in power output, while meeting stringent noise, smoke and other emission control standards which have been set in the U.S. Other work by the manufacturers has been aimed at scoping the potential for alternative fuels and blends of other materials with diesel fuel (alcohols, vegetable oils, propane and gasoline are potential extenders).

The truck diesel engine changes foreseen for the future include: engine derating (lowering rpm and power output) to achieve fuel economy; the use of turbo compounding to recover exhaust heat and power in addition to that normally recovered through the use of turbochargers; the use of high temperature air-cooled "adiabatic turbo compounded engines" (where multi-fuel capability, combustion efficiency improvements, reduced noise, elimination of uncombusted fuel "white smoke", with a reduced compression ratio engine are possible) and other changes, such as air charge cooling (to increase air intake, reduce combustion temperature, improving NO_x and hydrocarbon emissions and fuel economy).

Some of these changes can be implemented within the next few years (air intake cooling for example), others, such as the "adiabatic" engine will require a decade of development and gradual introduction. The longer term solutions appear capable of easing the transition to the lower grade diesel fuel which will be the norm in the 1990's, higher temperature combustion in the adiabatic engine being particularly important. The fuel formulation needed to optimize the performance of these engines is not now known.

The cetane quality required in railway diesel engines is already low. CN, for example, has been operating for years with a tar sands-derived, lightly refined, gas oil side-stream with a cetane value in the region of 33. This trend will continue with rail and marine diesels (slower speed, therefore less dependent than truck engines on ignition quality and ignition delay) receiving light fuel oil and other non-premium fuels in

the diesel fuel boiling range. A trade-off is struck between increased maintenance on the one hand and fuel price and availability on the other.

Spark-assisted diesel engines may be in vogue late in the century if high quality diesel supplies cannot be obtained. Such engines could operate on gasoline/diesel blends, or other 'gasoline-like' fuels, and approach high compression spark ignition and stratified charge engines in their design and fuel requirements. These engines are not likely to be a significant component of the vehicle fleet before the end of the century and since they are appropriate to the use of gaseous fuels or coal liquids rather than diesel fuel, they will not influence short-term refinery designs and investments related to the urgent problem of diesel fuel quality enhancements. They may, however, influence the direction of refinery R&D.

The techniques for diesel fuel quality enhancement involve fundamental changes in the chemistry of low quality 'diesel fractions' by hydrotreating and hydrocracking and by the use of cetane improvers (usually expensive organic nitrates), smoke suppressants and pour point additives (to modify viscosity at low temperatures). New approaches are needed in view of the importance of the diesel engine to the economy, the magnitude of the fuel quality deficiency problems and the costs of supply/quality solutions.

2.4.3 Jet Fuels

There are two types of aviation jet turbine ('turbo fuel') in use in Canada - a kerosene type Turbo fuel A-1 which comprises 63% of the total jet fuel used, and a wide boiling, predominantly naphtha type Turbo fuel B which may be viewed as a wide-cut gasoline.

Jet A-1 is favoured for international jet service, the lighter, more volatile B by the military and general aviation and increasingly by Canadian airlines because of its better low temperature flow properties and ease of starting in winter; Jet B is widely used in the north of the

country.

The growth of jet fuel demand in the future is expected to be lower than the 5% annual rate in the past decade, due to price, availability and the introduction of improved fuel-conserving flight and passenger management logistics and the new generation of fuel-efficient engines and aircraft which are just now entering commercial service in such aircraft as the Boeing 767. Fuel costs have become the dominant operating cost factor for the airlines, having risen since 1970 from about 25% of direct operating costs to 56% in 1980 and are forecast to exceed 64% by 1985: old style long haul jets must therefore be replaced or re-engined. Massive replacement of the current aircraft fleet cannot occur at short notice and up to 90% of the predicted consumption of aviation fuel by the year 2000 will be incurred by aircraft and engines now in existence, or under current development.

The expected growth in demand for air transport services measured in passenger miles, or ton miles (freight) is 5% per year, producing a forecast wherein the annual jet fuel demand growth to 2000 will be in the range of 3 to 4% per year, with the lower rate applying in the early stage when maximum benefit accrues from conservation practices and engine replacement or modification to lower fuel consumption and a higher rate applying in the later years as continued growth of air transport occurs in a period when fuel economy gains slow - the easier savings having been accomplished. The modest share of the aviation fuel market held by aviation gasoline is expected to decline relative to turbo fuel in the period, but in absolute terms volume is forecast to increase 40%.

The specifications for turbo fuel are complex: some 23 properties are specified, compared to 6 for gasoline and 11 for diesel fuel, reflecting the need to control composition, volatility, fluidity, combustion, corrosion, storage stability, contaminants and electrical conductivity of the fuel over the wide range temperature and pressure encountered at ground level and high altitude transcontinental and international flights. The principal compositional constraint is on the carbon to hydrogen ratio of the fuel

which affects its specific energy (power output per kilo of fuel) and tendency to smoke, which affects combustor temperature and hence engine life. The hydrogen content of conventional kerosene is typically 14% by weight, but numerous values of specifications on aromatic content, smoke point, freezing point (which are tied to the hydrogen content), must be relaxed through specification waivers and later new specifications to adjust to the lower hydrogen content of jet fuel quality deterioration that accompanies the increased use of high aromatic and heavier fractions from the refineries operating on current petroleum crudes, heavier crudes and syncrudes from tar sands and heavy oil, and beyond 2000, coal-based syncrudes. Many other properties in addition to hydrogen content, or aromatic content, are critical to safety, engine life and performance and any new refining process scheme or syncrude source must be exhaustively tested to ensure that the aviation turbo fuels they produce meet stringent quality standards.

The room for relaxation in specifications is limited and jet fuel yield may become the limiting factor in refinery production: the recent relaxation of Jet A fuel specifications on flash point (from 38°C to 33°C) and freezing point (-50°C to -47°C, or -45°C in summer) could, if utilized, provide a 2% addition to crude run in refineries operating with typical western Canadian conventional crudes. Syncrude blending with conventional crude and eventual use of syncrude as a sole feedstock will need new standards and new refining technologies. Eventually new aircraft engines must also be developed to burn lower quality fuel; fuel systems must also be changed to incorporate pressurized fuel storage and other means to handle 'broad-cut' aviation fuels. Canada's current experience with the naphtha-based 'broad-cut' fuel is a good base from which to develop these new fuel handling systems.

2.4.4 Other Fuels

Fuels required for marine transport fuels are projected to grow at a modest 1.6% annual rate in the next twenty years, the growth in fuel demand reflecting expansion of Canada's external trade and fisheries offset

by fuel conservation measures, such as 'slow steaming', now essential in this competitive industry where fuel costs have reached 40% of operating costs in typical merchant ships powered by diesel engines fired by diesel fuel or heavy fuel oil (in low speed marine diesel engines).

The proportion of heavy oil demand relative to diesel fuel (currently 2:1) is expected to decrease slightly, reflecting continued high availability of heavy oil from other sources and the loss of some Canadian bunker fuel sales to international carriers, but also in response to the increasing cost of treating heavy oil on board as quality deteriorates as inorganic residues and high molecular weight products are increasingly concentrated in the bottom of the barrel, as refineries are operated to yield the maximum of light distillate products, often from heavier, sourer crudes.

In the future the choice of marine propulsion machinery will be increasingly governed by thermal efficiency considerations and the medium speed diesel (43% thermal efficiency, uses marine diesel fuel), and low speed diesel engine (41% thermal efficiency,uses heavy oil) will gain over the steam turbine (31% thermal efficiency, uses heavy oil) and particularly over the gas turbine engine (28% thermal efficiency, but requires high quality distillate), except in special circumstances such as naval vessels and LNG carriers where the gaseous cargo fuel boil-off would be used.

Elsewhere in the liquid fuel market, sharp declines in use are forecast for light fuel oil and heavy fuel oil as the role of non-liquid fuel alternatives, such as natural gas and electricity, grow in response to price, incentives to conversion and other measures broadly stated in the NEP and the oil pricing agreements with the western provinces. The NEB "Canadian Energy" study forecasts a 5% per annum decrease in the demand for light fuel oil in the next few years and about the same (-4.9%) for heavy fuel oil.

2.4.5 Non-Fuel Liquids

Oil is used not only for the productionof liquid fuels, but also as the source of numerous petrochemicals, some of the liquified petroleum gas

(LPG, propane, butane) used in Canada or exported, of lubricating oils, industrial solvents and road asphalt.

The petrochemical industry is the major non-fuel outlet for oil, but also uses natural gas and natural gas liquids, ethane, propane and butane.

In the original NEP (1980) the aim was set to restrict growth of oil use in this sector to zero, but industry and the NEB agree that an average annual growth of 4.7% is likely in the period to 2000, with oil consumption for petrochemicals increasing from 11,000 m^3/day in 1980 to 27,500 m^3/day by 2000. The impact of OPEC production of petrochemicals and the extent of conversion of petrochemical production to natural gas liquids feedstock (limited by the demand for aromatics) will greatly influence oil use in this sector.

The production of lubricating oils and greases from petroleum stocks will continue to be important in the future and changing feedstocks to refineries will require changes in processing methods to attain existing specifications and provide new products to match competitive synthetic lubricants now being introduced into high stress applications, such as lubricating oils for aero engines and trucks.

Finally, we reach the bottom of the demand barrel and we note that refineries will continue to meet the need for road asphalt and coke by the processing of residuals and topped heavy oils. The contribution of these items to the refinery balance and profitability is important, as is the maintenance of specifications for special grades, such as electrode coke and pitch supplied to aluminum smelters. The selection of new crude sources and refining processes cannot ignore the demand for these products.

2.4.6 Summary of Fuel Demand Implications

The changing pattern of demand for petroleum products will have the following effects:

- a diversion of heating fuel (LFO) to jet and diesel fuel use will occur to accommodate the surplus of LFO and the demand for transport distillates. Transport distillate quality will deteriorate.

- gasoline may be in surplus supply, if refineries cannot adapt to the lower gasoline-to-distillate ratios, which can be met by changes in feedstocks, processing schemes and refinery equipment. The surplus will be in low (clear) octane grades.

- problems may be foreseen in the attainment of the needed supply of jet kerosene, winter-grade diesel and high-octane gasoline.

- changes in fuels ratios and standards may alter the total costs and relative costs of transport fuels. Transport distillates may be affected most.

- a role may be developed for alternative fuels not based upon oil.

Further examination of these effects on the refining of oil in Canada is contained in Part 2.

PART 2: REFINING IN CANADA

1. THE REFINING PROCESS (A VERY SIMPLIFIED VIEW)

1.1 Crude Oil Quality Differential

Both the gravity (density) and the chemistry of oil are important to the total yield of fuels which can be wrung from a barrel of crude and the distribution of that yield among gasoline, jet, diesel, light fuel oil and heavy fuel oil. The chemistry and gravity also determine oil throughput in the refinery units, such as reformers and crackers which largely control the costs of oil processing.

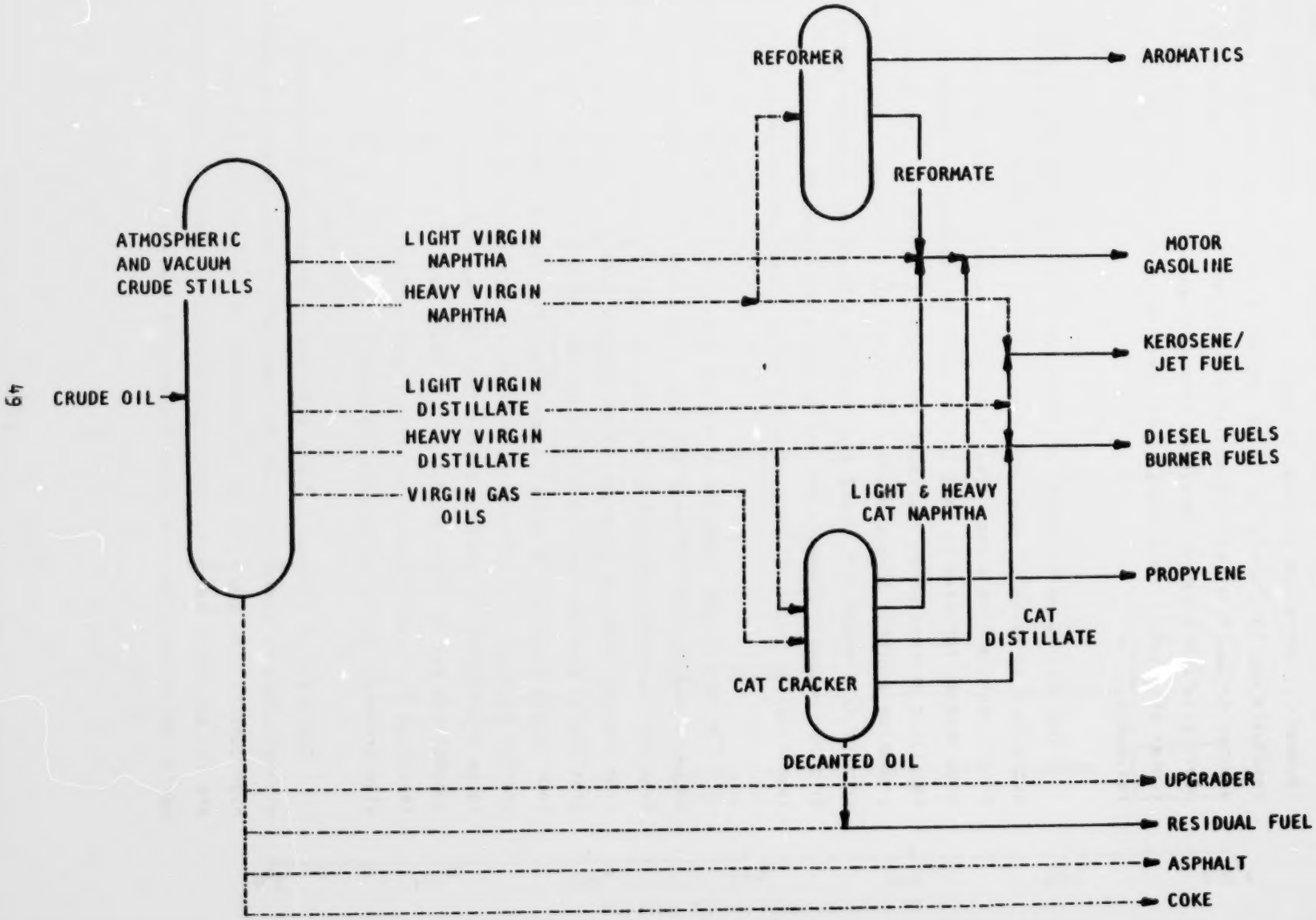
The gravity of crude oil is commonly measured by the API (American Petroleum Institute) gravity, where the API gravity measured in degree (API^{o}) increases with ease of processing and quality. Normally sulphur contents of crude vary inversely with the API gravity. The value of a given crude oil is commonly measured by its gravity and sulphur content. An average quality for oil in Canada would be $38^{o}API$ gravity and 0.5% sulphur content: price adjustments outlined in the Canada/Alberta 1981 Energy Pricing and Taxation Agreement use this quality as the bench mark for the new oil reference price (NORP). When the price of the reference new oil is $47.30 per barrel (early 1982), the quality differential will be 22¢/$1^{o}API$ and 16.5¢/0.1% sulphur - a $15^{o}API$ and 35% sulphur crude would therefore command $37.50 per barrel, a $42^{o}API$ and 0% sulphur oil - $49 per barrel. The price of internationally-traded oil also reflects this adjustment for quality and yield of high value transport fuels.

1.2 The Refining Process

A simple refinery configuration is illustrated in Figure 9. In such a basic refinery crude oil is distilled at atmospheric pressure (perhaps also at reduced pressure) to provide virgin streams of naphtha, light and heavy distillates and a gas oil fraction. The residual oil from the

Figure 9

A SIMPLE REFINERY CONFIGURATION



distillation may be sold directly as a residual, blended to heavy fuel oil (Bunker C), converted to coke, or asphalt. In more complex refineries the residuals may be transferred to an upgrading unit to be cracked, producing another crude oil stream (essentially a synthetic crude). Naturally occurring heavy oils and bitumens recovered from tar sands go directly to an upgrader (coker or cracker) to produce syncrudes, which on refining do not produce residuals.

The boiling point ranges of fractions distilled from oil and their assignment to sales of gasoline, diesel, etc., are illustrated in Figure 10. Virgin naphtha from direct fractionation is normally of insufficient quality (low octane) for sale as gasoline and must be upgraded by reforming - a catalytic process which increases the aromatic content of the gasoline, producing a higher octane product and by-product hydrogen. The reformer product is blended with other fractions to a gasoline to which lead alkyls, or other octane improvers, and antioxidants are added to produce specification grades of regular and premium leaded and unleaded gasolines.

The next higher fraction of virgin distillate is valued for its low smoke, clean burning tendency and low temperature flow properties. This fraction (kerosene) is used to produce jet fuel by blending with like streams from cracked products (for Jet A) or naphtha (Jet B). Higher boiling virgin distillates are used as blending stock for the production of high quality (40+ cetane number, low smoke) diesel fuel for trucks, buses and automobiles, whereas heavier virgin fractions and recycle (cracked) products are used in large proportions to produce diesel fuel for heavy equipment, railway locomotives and as a burner fuel. The heavy gas oils are also used as feedstock for cracking to high value light products, which step, unfortunately, also produces low value gaseous products.

The yield of transport fuels attained by distillation conducted without cracking operations does not meet market requirements, even when a high quality (low gravity, low sulphur) crude is processed and such crudes are in any event becoming scarce and expensive. Table 8 shows the wide variation in yield obtained with crudes of different origins (and gravities).

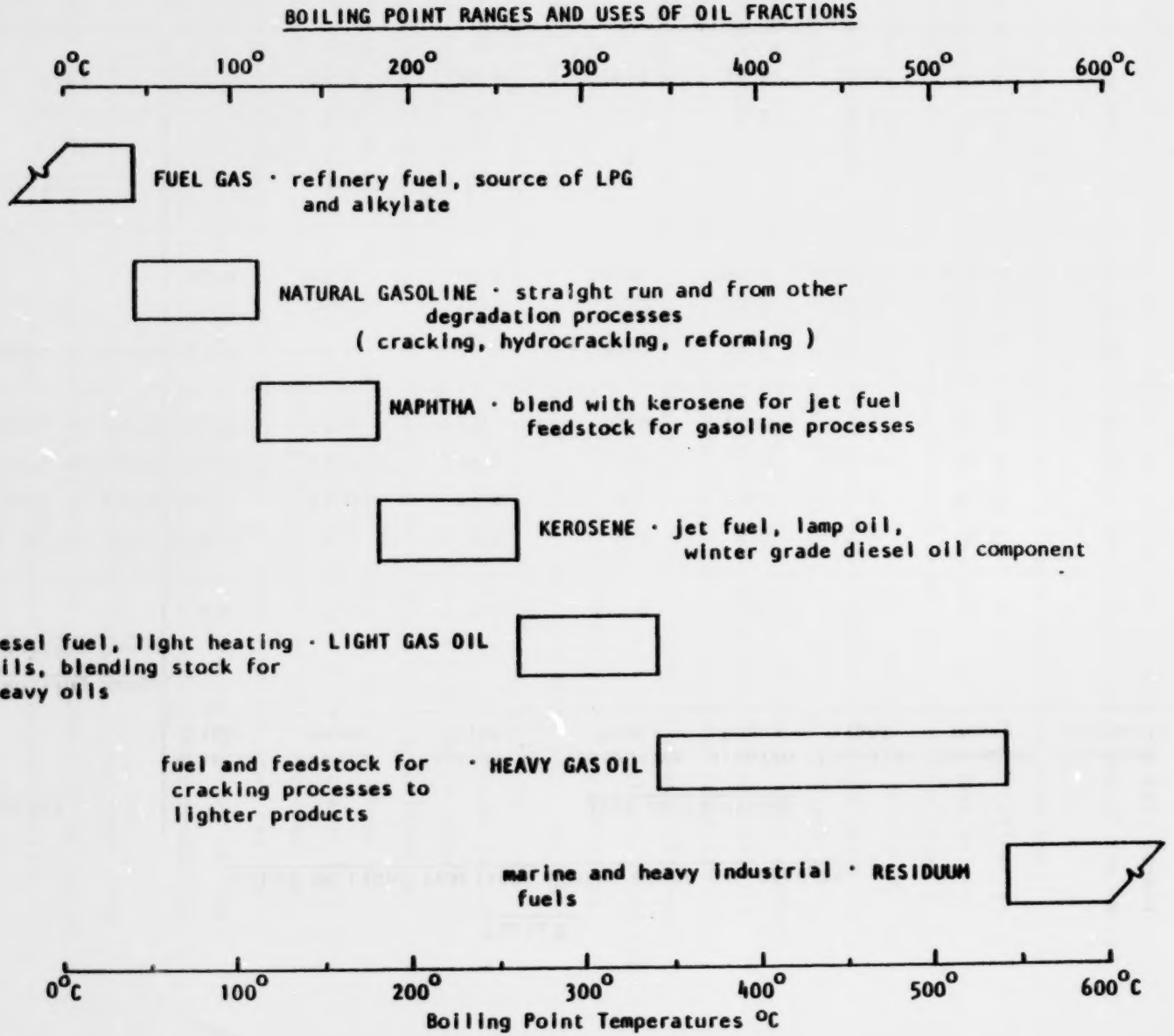

BOILING POINT RANGES AND USES OF OIL FRACTIONS
0°C
100°
200°
300°
400°
500°
600°C
FUEL GAS · refinery fuel, source of LPG and alkylate
NATURAL GASOLINE · straight run and from other degradation processes (cracking, hydrocracking, reforming)
NAPHTHA · blend with kerosene for jet fuel feedstock for gasoline processes
KEROSENE · jet fuel, lamp oil, winter grade diesel oil component
diesel fuel, light heating oils, blending stock for heavy oils · LIGHT GAS OIL
fuel and feedstock for cracking processes to lighter products · HEAVY GAS OIL
marine and heavy industrial fuels · RESIDUUM
0°C
100°
200°
300°
400°
500°
600°C
Boiling Point Temperatures °C

Table 8

YIELDS OF LIGHT FRACTIONS VERSUS CRUDE OIL GRAVITY

Characteristics		Type of Feedstock								
		Arabian Light	Arabian Heavy	Venezuelan Light	Venezuelan Heavy	Iranian Heavy	Canadian Light	Canadian Heavy	Canadian Synthetic	Canadian Condensate
A. Volume % vs. Boiling Range										
Component	**Boiling Range**									
C_4 & lighter		2.0	3.5	2.0	1.0	2.0	5.5	1.7	0	6
Natural Gasoline	C_5 to 92°C	9.5	8.5	8.0	2.0	8.0	10.5	6.3	4	53
Naphtha	90°C to 175°C	14.5	11.0	13.0	6.0	14.0	17.0	11.0	11	34
Kerosene	175°C to 260°C	16.0	12.0	14.5	7.0	15.0	15.0	10.1	18	7
Light Gas Oil	260°C to 340°C	15.0	12.5	13.5	15.0	14.0	14.5	14.1	26	0
Heavy Gas Oil	340°C to 540°C	27.0	24.5	31.0	32.0	24.5	24.5	29.5	41	0
Residuum	540°C	16.0	28.0	18.0	37.0	22.5	13.0	27.3	0	0
		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
B. Other Characteristics										
Item	**Unit**									
Sulphur	wt %	1.7	2.8	1.4	2.4	1.6	0.4	2.4	0	0
Gravity	°API	34.4	28.2	30.4	16.8	30.8	39.0	25.1	27.7	63

Source: MHG International/EMR data reported by Monenco Ltd. in "An Investigation into the Future Availability of Fuels for the Transport Sector" to Transport Canada, June 1981.

In Figure 11 the distribution of product fractions obtained from a typical Canadian oil by simple distillation (straight-run) process is compared to the actual distribution obtained in the refineries of west and east Canada, where complex processing and blending are used to meet the needs of the market.

There is a hierarchy of refineries in Canada which range from the simplest distillation unit at Norman Wells to a number of small refineries with distillation, reforming and hydrotreating units (which remove sulphur from distillate fuels with hydrogen from the reformers) to others where a range of complex refining operations are conducted, including recycle of heavy fractions to catalytic cracking and hydrocracking units and means to recover values from heavy residues by coking: all designed to maximize the yield of transport fuels from the oil processed. Cracking steps produce light gases, part of which may be used to synthesize high-octane synthetic gasolines: these may require the acquisition of non-petroleum feedstocks such as isobutane for the synthesis operation. The preferred synthesis alternatives are termed 'alkylation and polymerization', but other synthesis processes are becoming available (producing, for example, the high octane additives MTBE and Dimate). The wide scope of the refinery processes which may be practiced can be judged from the schematic of an 'integrated' refinery shown in Figure 12. Such refineries may contain a unit to upgrade residuals by coking, which process provides a coke residue and a stream of coker overheads (coker naphtha, distillate, gas oil) that may be stabilized by hydrotreating and then combined with virgin liquid streams for blending directly to specification grade fuels, or to pooled refinery streams for further processing, such as reforming to gasoline, or catalytic cracking to gasoline and distillate streams. Each of these then provides residual fractions for further processing, or an exit from the refinery as residual oil, asphalt, coke, or special heavy fractions for carbon black production.

Other configurations and process steps are frequently practiced; the most important for future consideration being the replacement of the coking step by hydrocracking processes, which hydrogenate low hydrogen-content residual streams, while cracking them to simpler species to swell the production of liquids at the expense of coke. These hydrocracking processes

Figure 11

CANADIAN REFINERIES OUTPUT

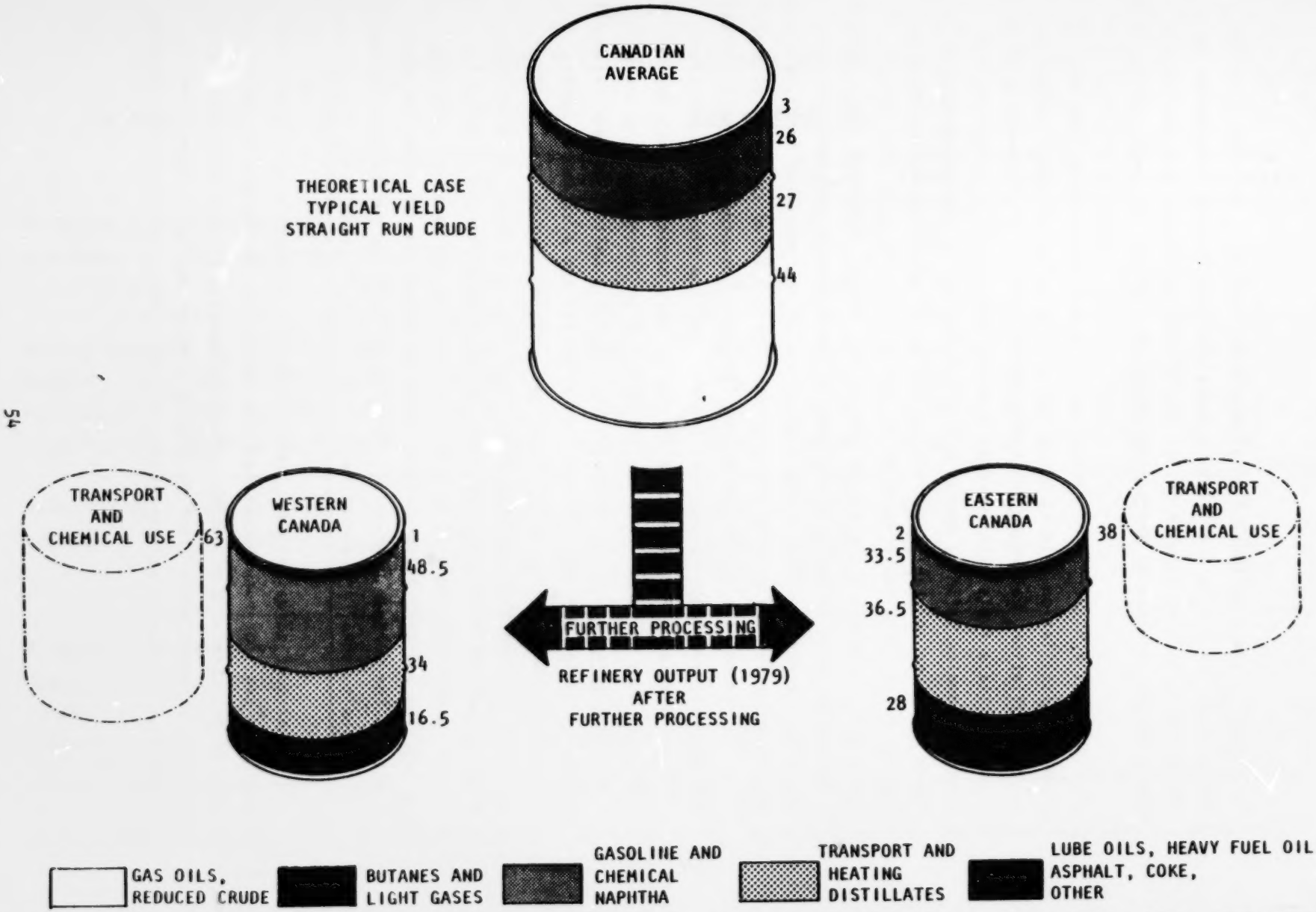
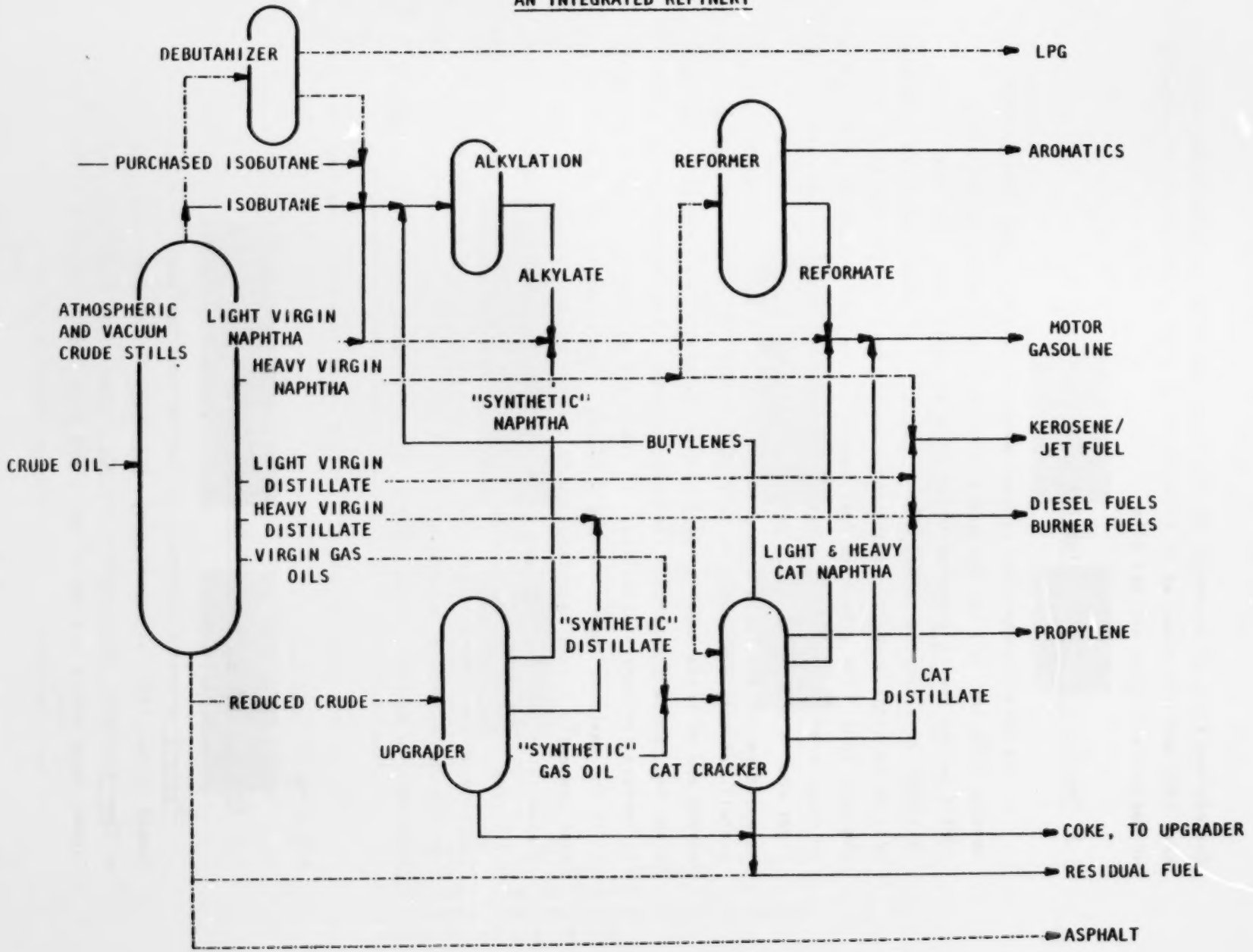


Figure 12

AN INTEGRATED REFINERY



for residuals are an extension of catalytic hydrocracking processes, which have long been practiced as an alternative to thermal and catalytic cracking of heavy distillates and gas oils.

1.3 The General Refinery Situation in Canada

At the moment demand for refined products is declining. The decline between 1980 and 1981 was 6%, and a further 5-6% is expected for the 1981-2 period and is expected to continue at least until the late 1980's (although at a reduced rate), when a resumption of petroleum product demand will bring total product and oil requirements back to 1980 levels by about the year 2000. The growth in fuel demand in the next decade is likely to occur predominantly in the Western provinces, where refining capacity is tight and is being expanded. Refineries in Ontario, Quebec and the Atlantic region are faced with a decade or more of declining demand, and overall refinery over-capacity in a period when the pattern of product demand and of crude supplies will change, necessitating changes in refinery practice. Certain essential refinery equipment investments must be made to improve refinery flexibility. If these are not made, it may be necessary, as in the past, to import refined products. The prospect in the east is that presently closed facilities (Gulf's Point Tupper refinery on Cape Breton Island and Petro-Canada's Come-By-Chance, Newfoundland refinery) will remain closed, and others operating below economic levels may also close. Start-up of the Come-By-Chance facility to refine Hibernia crude would require corresponding reductions in refinery capacity, or utilization, elsewhere in eastern Canada, unless refined product exports are authorized.

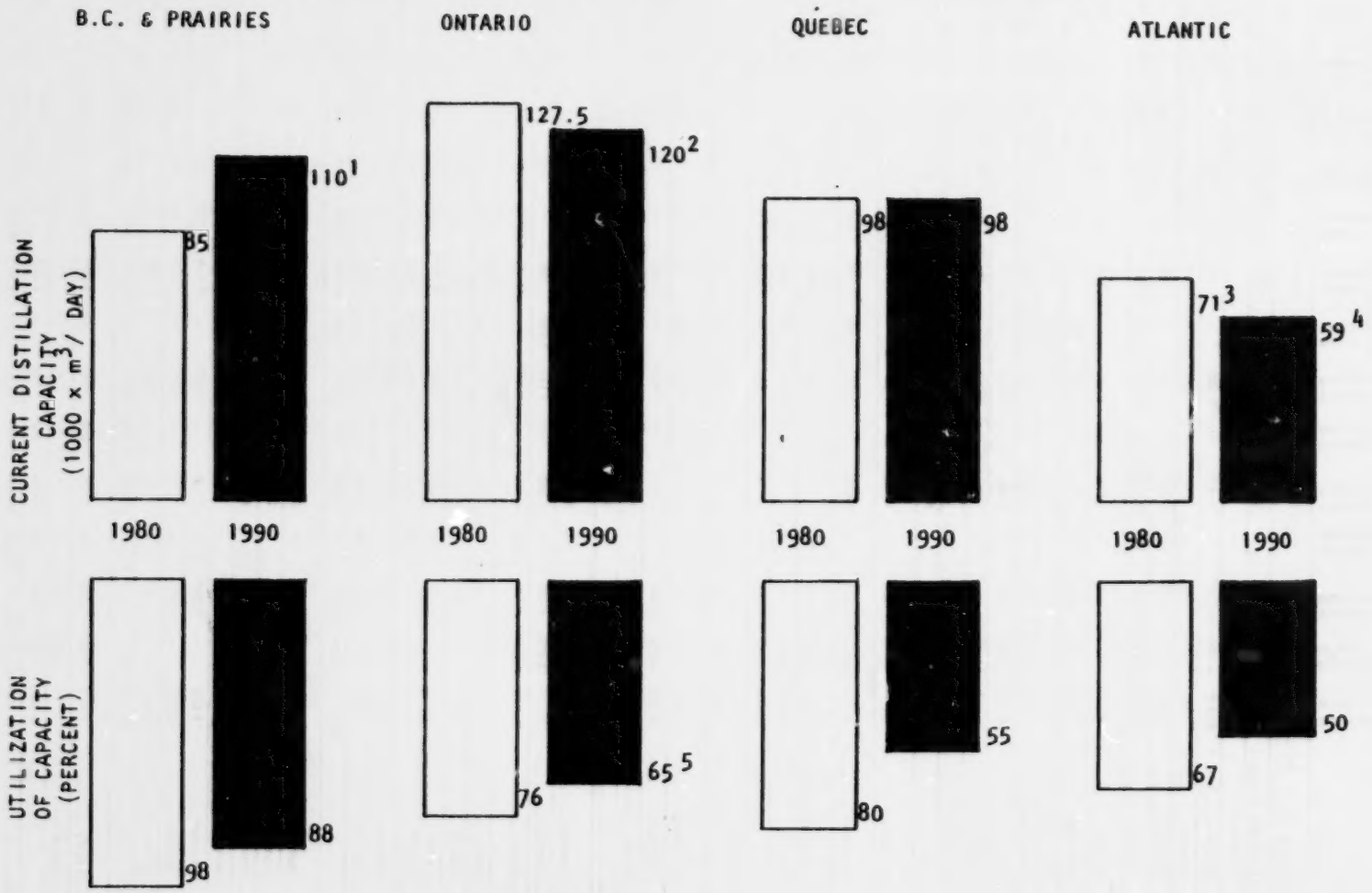
The current capacity and utilization rates in each of the four regions are given in Figure 13.

1.4 Refinery Equipment in Place and Planned

Table 9 presents a summary of the refinery equipment in place in Canada in May 1981, as reported by Oil Week. It includes idle facilities at Come-By-Chance, Newfoundland (15,900 m^3/day crude capacity), Point Tupper, Nova Scotia (12,880 m^3/day), and Port Credit, Ontario (7,630 m^3/day),

Figure 13

CANADIAN REFINERY CAPACITY AND UTILIZATION: 1980 AND 1990



1 PLANNED FOR 1984
2 EXCLUDES PORT CREDIT, ONTARIO
3 EXCLUDES COME-BY-CHANCE
4 EXCLUDES COME-BY-CHANCE AND POINT TUPPER
5 ALREADY AT 69% IN 1982

SOURCE: CAPACITY DATA- OILWEEK, FEBRUARY 1982.

Table 9

CANADIAN REFINERY CAPACITIES

Refinery	Location	Crude Capacity M³/cd	Crude Capacity M³ sd	CHARGE CAPACITY — M³ sd: Vacuum Distillation	Thermal Operations	Catalytic Fresh Fd	Cracking Recycle	Catalytic Reforming	Hydro Refining	PRODUCTION CAPACITY — M³ sd: Hydro Treating	Hydro Cracking	Alkylation	Polymerization	Lubes	Asphalt	Coke tonnes	Sulphur tonnes
ALBERTA																	
Gulf Canada	Calgary	1 380	1 480	400	—	—	—	—	—	—	—	—	—	—	830	—	—
Gulf Canada	Edmonton	12 720	13 670	4 610	—	4 770	—	2 310	7 150	950	--	1 590	—	—	—	438	103
Husky Oil	Lloydminster	1 820	1 900	1 110	—	—	—	—	—	—	—	—	—	—	870	—	—
Imperial Oil	Edmonton	24 010	24 590	8 010	—	7 160	—	3 500	—	7 470	—	1 590	—	460	2 000	—	36
Shell Canada	Bowden*	795	—	—	—	—	—	397	—	429	—	—	—	—	—	—	—
Texaco Canada	Edmonton	4 490	—	1 270	380	1 430	—	720	—	1 160	—	—	140	—	—	71	—
Total		45 175	46 570	15 400	380	13 360	—	6 927	7 150	10 009	—	3 180	140	460	3 700	509	139
BRITISH COLUMBIA																	
Chevron Canada	Burnaby	5 550	—	1 340	—	1 270	160	1 980	—	1 590	—	—	100	—	350	—	—
Gulf Canada	Kamloops	1 490	1 590	520	—	480	—	290	970	—	—	—	30	—	110	—	—
Gulf Canada	Port Moody	5 910	6 360	1 990	—	1 910	—	1 510	3 610	—	—	220	—	—	—	—	25
Husky Oil	Prince George	1 510	1 590	490	—	480	—	190	—	870	—	—	—	—	210	—	5
Imperial Oil	Ioco	6 520	6 590	2 770	—	2 020	—	1 030	—	2 750	—	—	160	—	Yes	—	—
Petro-Canada	Taylor	2 275	2 450	180	—	830	—	320	—	1 830	—	160	—	—	90	—	—
Shell Canada	Shellburn*	3 498	—	1 113	—	954	—	428	—	2 703	—	—	127	—	397	—	15
Total		26 753	28 178	8 906	—	6 671	160	3 798	4 580	9 873	—	379	417	—	1 154	—	48
MANITOBA																	
Shell Canada	St. Boniface*	4 770	—	954	—	1 182	—	1 304	—	1 272	238	—	79	—	318	—	—
NEW BRUNSWICK																	
Irving Oil	Saint John	37 780	39 474	10 334	—	3 020	—	6 121	8 029	7 154	5 247	—	302	—	2 067	—	200
NEWFOUNDLAND																	
Newfoundland Ref.	Come-By-Chance**	15 900	16 680	7 790	1 910	—	—	4 049	—	5 800	5 580	—	—	—	—	—	194
Ultramar Canada	Holyrood	1 910	2 070	—	—	—	—	220	—	620	—	—	—	—	—	—	—
Total		17 810	18 750	7 790	1 910	—	—	4 269	—	6 420	5 580	—	—	—	—	—	194
NORTHWEST TERRITORIES																	
Imperial Oil	Norman Wells	480	480	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NOVA SCOTIA																	
Gulf Canada	Pt. Tupper **	12 880	13 630	—	—	—	—	1 910	6 360	—	—	—	—	—	—	—	40
Imperial Oil	Dartmouth	13 350	13 750	6 860	—	3 980	—	1 430	—	7 150	—	—	410	—	Yes	—	40
Texaco Canada	Halifax	3 180	—	1 370	—	1 140	—	570	—	1 400	—	—	—	—	—	—	—
Total		29 410	28 910	8 230	—	5 120	—	3 910	6 360	8 550	—	—	410	—	—	—	70
ONTARIO																	
BP Canada	Oakville	12 719	13 514	6 636	—	3 616	191	2 743	—	4 213	—	795	—	—	1 590	—	—
Gulf Canada	Clarkson	12 590	13 510	4 450	—	2 860	—	3 180	5 090	1 590	—	570	200	1 030	1 020	—	40
Imperial Oil	Sarnia	20 030	20 067	4 770	3 560	4 130	—	2 230C 2 700SR	—	15 070	1 830	930	510	1 030	—	—	103
Petrosar	Sarnia	—	27 620	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Shell Canada*	Oakville*	6 996	—	1 828	—	2 228	—	1 113	—	4 611	—	385	—	—	111	—	50
Shell Canada	Sarnia*	11 765	—	4 134	541	2 544	—	3 704	—	3 767	1 192	—	—	—	—	—	31
Suncor	Sarnia	14 300	15 100	—	890	2 860	—	3 140	4 370	635	—	600	—	—	—	—	10
Texaco Canada	Nanticoke	15 100	—	4 930	—	6 360	—	3 820	—	3 820	—	1 180	—	—	—	—	—
Texaco Canada	Port Credit**	7 630	—	2 700	1 000	2 480	—	1 110	—	1 110	—	—	170	—	—	—	—
Total		127 710	133 201	29 648	6 051	27 096	511	23 940	9 180	34 851	3 022	4 508	880	2 060	2 721	—	237
QUEBEC																	
BP Canada	Montreal	11 288	11 924	2 941	—	3 180	158	1 908	—	6 836	—	—	159	—	1 749	—	—
Gulf Canada	Montreal	12 280	13 200	4 670	—	3 500	—	1 590	4 930	—	—	—	170	100	910	—	—
Imperial Oil	Montreal	12 400	12 720	7 470	—	4 050	—	1 910	—	8 270	—	—	430	—	Yes	—	—
Petrofina Canada	Montreal	14 800	15 100	7 150	—	3 180	950	5 100	—	8 380	2 540	240	95	—	1 300	—	—
Shell Canada	Montreal*	19 078	—	8 267	1 431	3 736	—	3 657	—	10 636	2 067	254	—	524	1 271	—	—
Texaco Canada	Montreal	11 870	—	4 930	1 940	4 210	—	1 910	—	3 820	—	480	240	—	—	—	—
Ultramar Canada	St. Romuald	16 380	17 170	3 180	—	—	—	2 380	—	4 280	—	—	—	—	1 590	—	—
Total		98 106	102 564	38 608	3 371	21 855	1 108	18 455	4 930	49 212	4 607	974	1 064	624	6 820	—	—
SASKATCHEWAN																	
Consumers Co-op	Regina	8 840	7 600	2 860	560	2 100	240	1 590	—	2 380	—	—	240	—	—	168	—
Gulf Canada	Moose Jaw	2 110	2 230	1 220	—	—	—	—	—	—	—	—	—	—	920	—	—
Total		8 950	9 830	3 600	560	2 070	240	1 590	—	2 380	—	—	240	—	920	168	—
TOTAL ALL CANADA		396 302	414 897	123 279	12 272	80 388	2 020	70 315	40 229	119 921	18 674	9 033	3 562	3 144	17 770	677	892

*All Figures reported per calendar day

**Mothballed

***Only LPG units operating

Provincial totals for stream day crude capacities converted from calendar days using 0.95 factor for crude and vacuum units and 0.90 for all other processes.

a total of 36,410 m^3/day of idle capacity - 9% of the total crude capacity of 396,000 m^3/day in place in Canada.

Canada's 39 refineries have an average name-plate crude distillation capacity of 10,000 m^3/day and the smaller refineries have low flexibility and higher costs than the large and fully-integrated facilities, such as those operated by Gulf and Imperial in Edmonton. (Small units dedicated to the conversion of heavy oil to asphalt are an exception).

Table 10 lists the changes to refinery capacity announced in the period 1979 to April 1982 and the capacity seen to be available in the period 1985-90. The major additions to capacity under construction, or planned at this time, which affect refinery flexibility, are of the following types:

1. Expansion of total refinery output in the western provinces, including two grass roots refineries in Alberta (Shell at Scotford and Turbo Resources at Balzac).

2. Facilities to increase the conversion of heavy fuel oil and vacuum gas oil:
   - Suncor (Sarnia, Ont.)
   - Petro-Canada (Montreal, Que.) - vis-breaker installation
   - Ultramar (St. Norman, Que.) - vis-breaker installation
   - Petrosar (Sarnia, Ont.)
   - Imperial Oil (Montreal, Que.)
   - Studies and pilot plants: Carmont, Montreal upgrader; Saskatchewan upgrader.
   - Plants under consideration: Carmont, Montreal upgrader; Saskatchewan upgrader.
   - Petro-Canada (Montreal, Que.) - residual upgrader demonstration unit.

3. Facilities to increase distillate yields:
   - Imperial Oil (Sarnia, Ont.): hydrocracker reactivation
   - Ultramar (St. Romauld, Que.) and Imperial (Sarnia, Ont. and Montreal, Que.), noted above.

Table 10

COMPOSITE REFINERIES BY REGION: 1979 CAPACITY
AND MAJOR ANNOUNCED ADDITIONS FOR 1985-90 CAPACITY (Totals may not add due to rounding)

Changes to 1979 Composite Refineries Company	Location	Crude Unit	Vacuum Distillation	Catalytic Reforming	Catalytic & Hydrocracking	Distillate Desulphuriz.	Poly & Alkylation
		REFINERY UNIT CAPACITIES m^3/day					
ATLANTIC REGION							
1979 Base Case		71,250	17,500	10,000	13,250	19,950	400
Gulf	Point Tupper (shutdown)	(13,000)	-	(1,715)	-	(4,160)	-
1985-90 capacity		58,400	17,510	8,300	13,250	15,800	400
QUEBEC							
1979 Base Case		98,000	37,000	18,000	26,050	25,600	1,920
Ultramar	Quebec City	-	5,560	-	4,800	-	400
Imperial	Montreal	-	1,600	-	-	-	-
Petro-Canada (1)		-	7,150	-	4,800	-	400
1985-90 capacity		98,000	44,130	18,000	30,800	25,600	2,320
ONTARIO							
1979 Base Case		120,350	28,450	22,300	27,500	12,900	4,250
Suncor	Sarnia	-	3,500	-	3,340	-	-
Petrosar	Sarnia	-	5,560	-	-	-	-
Imperial (2)		-	9,050	-	3,340	-	-
1985-90 capacity		120,350	37,500	22,300	30,800	12,900	4,250
WESTERN REGION							
1979 Base Case		84,950	27,500	14,900	24,200	18,350	4,180
Husky	Lloydminster	2,000					
Shell	Scotford	7,150	-	3,300	5,250	-	-
Turbo	Edmonton	4,800	1,200	1,525	1,800	-	-
Imperial	Edmonton	6,350	8,000	950	2,380	2,400	-
Gulf	Edmonton	7,150	950	950	2,250	4,000	-
Shell	Burnaby	1,900	-	-	-	-	-
		27,300	29,500	6,730	11,650	6,350	-
1985-90 capacity		112,250	30,450	21,650	35,850	24,700	4,180

Sources: 1979 data: Montreal Engineering Ltd. study for Transport Canada.
1985-90 from public announcements in press.

Notes: (1) Pilot plant for 800 m^3/day hydrocrackers using CANMET process
(2) Imperial reactivation of hydrocracker (1850 m^3/day)

4. Facilities to increase production of high octane unleaded gasoline and aromatics:

- Gulf Canada (Montreal, Que.)
- Shell (Scotford, Alta.) and Turbo Resources - grass-roots refineries noted above.
- Suncor (Sarnia, Ont)
- Shell (St. Boniface, Man.)

5. Lubricating oil recycle plants:

- Shell (Montreal, Que.)
- Mohawk Oil (Edmonton, Alta.)
- Imperial Oil (Sarnia, Ont.)

1.5 Refining Trends

The next two decades will be difficult for refiners as extensive reorganization of operations, construction of new capacity and the de-commissioning of large blocks of capacity will be necessary to improve the yield of transport fuels, to meet the burgeoning transport distillate demand with shrinking gasoline and heating fuel production (fuel oil is a traditional sink for low quality streams), and to accommodate very large changes in the origin and quality of crude oils processed. In addition, refiners must accommodate to the use of alternative fuels in their markets and, in certain cases, in their refineries. In the case of jet and diesel fuels, the demand explosion will require new refinery investments on the one hand, and a relaxation of quality standards on the other, which effects may spill over into other fuels, such as heating oil, which must provide an outlet for unwanted fractions where cracking cannot be practiced. Much under-utilized refinery capacity in eastern Canada will be retired.

The changes in refinery operation, equipment, and the quality deterioration which may be anticipated in the future in each of the four arbitrarily chosen regions of Canada (Atlantic, Quebec, Ontario, Western Canada)

have been sought with the aid of models; these permit simulation of the operations of regionally aggregated refineries fed with various crudes to provide the volumes of transport and heating fuels which have been forecast to be required in the future.

The simulation activity is performed by refiners and marketers, but similar investigations have been undertaken by NEB with its model, by the Energy Supply Allocation Board within EMR, by Monenco and Padgett Process Services for Transport Canada, each to answer a different set of questions and each with a different set of supply and demand data (due to timing in a dynamic supply condition). Reference should be made to these sources for detailed information on any particular region or fuel: the present analysis may serve as an introduction to these more detailed sources.

The approach taken here is to examine each region using one key supply scenario for the period to 1990 only. The somewhat optimistic scenario of substantial Hibernia production by 1990 given in Table 3, p. 18, is assumed. The demand forecast used is that chosen by the NEB as being most likely in 1985 and 1990 from industry hearings and its own analysis. A demand variant chosen for examination was a case in which the demand for transport distillates was increased. For this case the highest forecast made by industry of distillate demand, as taken from the NEB report "Canadian Energy Supply and Demand 1980-2000",was chosen. This represents an extreme distillate demand. These were run through the refinery configurations anticipated in each region in 1985 and 1990 with feedstocks forecast by the optimistic supply scenario. An interpretation of the results follows (pp. 63-73): more detail is available in the Appendix. Commentary is also provided on page 73 on the results of other simulations by Monenco and NEB, where appropriate.

2. REGIONAL PRODUCT AND REFINING TRENDS

2.1 Major Trends

The major changes in the future to 1990 include:

1. The development of western demand and associated new refining capacity with reduction in the rest of Canada.
2. The switch to high quality crude oil from Hibernia in the Atlantic provinces.
3. Use of reduced quality of imported oil in Quebec, the onset of import of similar quality in Ontario.
4. A reduction in the quality of western crude oil.
5. Changes in the hydrocarbon octane requirement to offset lead phase-out in gasoline.
6. Changes in the volume and quality of heating oils produced which now serve as sinks for off-specification distillates.

The effects of these changes on transport fuels include:

1. A general deterioration of the quality of diesel fuel which could lead by 1990 to acceptance of the specifications already under investigation by the CGSB and of the poor vehicle performance which may be associated with lower quality of diesel fuel (poor cold start, higher smoke production, higher corrosion rates than at present).
2. A modest degradation in the quality of jet fuel to 1985; a serious degradation thereafter shown principally by the decrease in jet fuel smoke point which degrades performance (lower life of combustors with more aromatic fuels burning with smokier flames at high internal temperatures, fuel viscosity problems at high altitudes, increased hazard with higher Jet B volatility).
3. A potential over-supply of low octane gasoline due to a rapid reduction in the demand for leaded regular grade gasoline and the incursion of diesel fuel in the automobile market. No problems are foreseen in meeting the forecast leaded/unleaded gasoline ratios, but problems would arise with lead phase-out.

The effects on refineries include:

1. A requirement to 1985 for heavy oil upgrading in the western region (3,000 m^3/day) and in Quebec (800 m^3/day), which may be a temporary requirement if syncrude production increases in the west and Atlantic offshore light crudes are emphasized, with a corresponding reduction in the residual fuel production.
2. An increase in the production of heavy distillates from syncrudes and the changing gravity of imported crudes will necessitate an increase in cracking operations to convert the streams to light transport fuels. Catalytic cracking will be at high levels in Ontario and Quebec and the by-product cracked gases (olefins) should be converted to synthetic gasolines (polymer gasoline, alkylate) which may require an expansion of these facilities by 1990. The situation is reversed in the Atlantic region where lighter natural crudes are to be processed after 1985.
3. The announced refinery expansions in the western region are adequate to meet the higher level of crude and syncrude to be processed, which results from overall growth of the market in that region.

The regional trends are next examined under the assumption that operations will be conducted to meet market demand and with minimum oil use (including maximum use of refinery olefins).

2.2 The Atlantic Region

2.2.1 Refinery Operations (interpreted within the given scenario)

The design and operation of refineries in this region have been influenced in the past, on the supply side, by refineries located at coast sites importing foreign crudes (normally heavier and sourer than domestic crudes), and the absence of a supply of gas condensates. The absence of a gas liquids supply accounts for the fact that no alkylation units are in place in the Atlantic region.

The principal demand side consideration in the Atlantic region has been the high use of fuel oil for heating purposes in the absence of a supply of natural gas. The large market for light fuel oil explains the low proportion of cracking capacity in place, compared to the rest of

Canada. The cracking capacity includes a high level of hydro-cracking. (The Irving, Saint John, N.B., refinery has 40% of the operating hydro-cracking capacity in Canada. Reactivation of Come-By-Chance would double that figure). The refinery capacity in the Atlantic region is therefore well-placed to provide the low gasoline-to-distillate ratios required in the future, when operated on Hibernia light crude oil. Exploitation of this gasoline-to-distillate capability will not be possible with heavy imported crudes (50% heavy is expected to be typical), until increased vacuum unit capacity is installed. At the moment, vacuum unit capacity in the region is only 26% of crude distillation capacity, and heavy ends must therefore be exported, since their use in marine fuels and for blending into lighter fuel oils is limited. With the advent of Hibernia, there would be no large requirement for residual fuel upgrading and therefore no consideration need be given to an Atlantic upgrader, but should the quality (gravity) of imported crudes degrade in the meantime, the vacuum unit capacity may be limiting and supplies of cracker feedstocks accordingly reduced.

The decrease in demand for gasoline in 1990 in the region and the low utilization of total refinery capacity indicate that the use of the cracking units (throughput and conversion) will be low and one, or more, of the cracking units could be shut down (unless export of finished products is allowed), and the Point Tupper refinery closed for good.

2.2.2 Gasoline Production in the Atlantic Region

The required levels of gasoline and octane can be met, even with reduced oil throughput, but the octane of the leaded grades will be achieved by increasing the lead content beyond the present level of about 2.5 ml/gallon used in the region.

The reduced requirement for all products is reflected in lower use of cracker capacity, the requirement for increased proportions of transport distillates by reduced levels of conversion at the cat.-cracker,

particularly when light Hibernia crude is run. The effect on the cracker output includes a lower level of olefin production, with the result that the polymer gasoline units are operated at low throughput, to the extent that 1990 throughput is one third or less than at present, but some reduction occurs even when heavy imported crudes are used.

The reformers can be run at constant severity, first at lower volumes to accommodate lower requirements for gasoline, but subsequently at higher throughput (option: higher severity) to compensate for lower polymer gasoline production, an increased requirement for high octane unleaded gasoline and the higher proportion of naphtha produced/barrel processed with light Hibernia crudes.

2.2.3 Jet Fuel in the Atlantic Region

The increased demand for jet fuel (A and B) is met by increased relative use of the vacuum unit and lower conversion in the catalytic cracker of heavy gas oil fractions. The major increase in jet fuel occurs through a reduction in quality as wider cuts are taken: this will not affect the low temperature performance (pour point), however. Thus the vapour pressure of Jet B is increased with more naphtha used, the end-point of the kerosene used is raised, thus increasing the density and aromatic content of the kerosene fractions in both Jet A and B. The result is to reduce the smoke point, but not below the specification limit. Sulphur levels increase with demand, but are reduced again when Hibernia crudes are run. Since the region is a small contributor to aviation fuel, the effect is limited.

2.2.4 Diesel Fuel: Atlantic Region

A 35% increase in the demand for diesel in the period 1980-2000 can be met while crude throughput in the region's refineries is cut 36% in the same period through use of a wider cut, and the acceptance of lower quality (except pour point, which is critical and can be maintained), until Hibernia

production provides the crude which is inherently suited to diesel production. Thus in 1985, the cetane number, gravity, sulphur content and final boiling point of diesel will all move in the direction of degraded fuel performance, but this is rectified with Hibernia crude. In the case where an increased yield of distillate is required, the degradations noted are more severe. Diesel, however, is within specification throughout.

2.2.5 Fuel Oil in the Atlantic Region

The pour point of light fuel oil may present a problem at high distillate yields, a parallel increase in gravity portends a smokier fuel than now provided. The quality of heavy fuel oil will deteriorate until Hibernia supplies become available when sulphur levels will be only 2.5% compared to 3% today.

2.2.6 Summary: Atlantic Region

In summary, the quality of transport fuels will not decrease significantly from today's values and the utilization of all process units will decrease with Hibernia oil. Unless export markets for refined products are developed (which will increase Quebec's dependence on imports), no prospects exist for the economic utilization of current moth-balled capacity and further refinery closures are inevitable. By 1990 crude processing requirements will amount to only 50% of the capacity of the crude units currently in place in refineries now in operation. This could decrease further when the gas pipeline from the west is operative.

2.3 Quebec

2.3.1 Refinery Operations (interpreted within the given scenario)

The oil supply forecasts indicate that Quebec will increase its dependence on imported crudes with a deterioration of the gravity and associated sulphur levels of crudes processed. Refinery unit use in general decreases with lower product demand, but the increased use of heavy crude (or syncrude) will require increased use of catalytic

cracking in 1990 after a downturn from 1979-1985. The increased level of cracking relative to total crude throughput will increase olefin production by 1990, beyond the capacity of current synthesis units (alkylation, polymerization); their expansion beyond 1985 is indicated. Heavy fuel oil is produced surplus to requirements (800 m^3/day by 1985) which may support an upgrader.

2.3.2 Gasoline in Quebec

The heavier feedstock will produce a lower naphtha yield that is also in demand in Quebec as a chemical feedstock. To obtain the required octane values in gasoline an increased severity in operation of the reformer unit is required after 1985. With the strategy to use olefins from cracking, the effect will be to reduce the level of lead required for the production of gasoline in 1990.

2.3.3 Jet Fuel in Quebec

The demand for turbo jet fuel in Quebec has been projected to decrease to 1985, returning by 1990 almost to 1979 levels of demand, in contrast to a steady growth in demand in Canada as a whole. A gradual deterioration in quality as measured by sulphur content, smoke point and increased gravity will occur when the pour point is maintained at today's levels. The vapour pressure of Jet B will increase with added naphtha used to stretch kerosene supplies. The quality deterioration will approach the lower limits acceptable for commercial jet fuel, particularly after 1985 in the case where increased levels of diesel fuel are also required.

2.3.4 Diesel Fuel in Quebec

The required levels of diesel fuel can be produced, but only at considerable quality reduction, especially where large increases are required (the high distillate case) without sacrifice in cloud point behaviour (i.e. without increasing filter clogging in winter). The gravity (hence aromaticity, black smoke production, cold-start) deteriorates

to the specification limit by 1990 with a concomitant increase in sulphur levels (hence corrosion increases) to 0.4 weight %. While none of these property deteriorations alone will have a major effect on diesel vehicle performance, the cumulative effect will be to increase the frequency of malfunction, smoke output and engine wear and corrosion.

2.3.5 Fuel Oils

The gravity and sulphur levels of light fuel oil in Quebec will increase over the period. Problems will be experienced with the viscosity of bunker C and the sulphur level will increase. An excess of heavy fuel oil must be produced by the existing refinery configurations to meet the transport fuel demand. As discussed, a central upgrader for these residuals is indicated for use in the period to 1990. Its fate beyond then, should Atlantic crude oil production increase, is questionable.

2.4 Ontario

2.4.1 Refining Operations (interpreted within the given scenario)

The simulations for Ontario indicate that the advent of imports of crude oil with an API gravity lower than that now used with or without added volumes of syncrude (containing large quantities of heavy gas oil) will seriously affect the refinery output. The effects are qualitatively the same as in Quebec, but quantitatively more severe, since the crude quality change is also more severe.

Thus, while the use of crude distillation units decreases, that of the vacuum units will increase and approach the expansion level by 1990. Processing of heavier feeds will increase the use of cat crackers, which again may need capacity expansions after 1985, even when increased conversion rates are employed. Heavy cracking with the constraint of maximum use of the derived olefins increases the need for polymerization and alkylation, both of which were operating close to capacity in 1979 and will need expansion, especially when the reformer throughputs are reduced to

correspond to reduced naphtha make (heavy crudes) and gasoline demand. Without expansion of the alkylation and/or polymerization units, olefins from the catalytic cracker could provide excess olefins to the extent of 1200 m^3/day of oil equivalent which can only find use as a refinery fuel.

2.4.2 Gasoline in Ontario

Gasoline production with full utilization of the alkylation and polymerization units can meet required volumes and specifications with an increase in the use of lead in the reduced volumes of leaded regular gasoline sold; lead use is particularly high in the 1985 period, but within current legislative limits. The high end point of the naphtha fraction may cause certain performance problems (plug fouling, crank case dilution) in the derived gasolines. Naphtha is required for petrochemicals as well as gasoline in Ontario: the yield may be expanded by raising the end point.

2.4.3 Jet Fuel in Ontario

The gravity and smoke point of both Jet A and Jet B will deteriorate as higher levels of aromatics are incorporated. Jet A production by 1990 will be below current specifications on smoke point even when sulphur levels do not degrade further, when the gravity level (which reflects aromatic content and end point) also approaches the current maximum limit of the specifications.

2.4.4 Diesel Fuel in Ontario

The diesel fuel requirement for Ontario beyond 1985 will be difficult to achieve when the new qualities of crude are used, since the oil throughput in refineries will be reduced by 5.5% in 1985 and 9% by 1990, while diesel demand increases by 37% and 70% respectively over the demand in the base year, 1979.

Retention of the low temperature pour point (-35°C) is assumed, but it, like other critical specifications, may need to be revised to reflect the quality of supplies. These degradations will occur in either case where imported heavier crudes are used in Ontario's refineries, or western synthetic crudes are moved east. In the worst case with heaviest diesel demand, the cetane index, and especially the gravity, of Ontario's diesel fuels will be substantially below current specifications, in the best case at the margin of acceptance.

2.4.5 Fuel Oils in Ontario

The quality of light fuel oil in Ontario will be poor, since it, like diesel fuel, will be high in gravity exceeding specifications, or at the margin in 1985, deteriorating further by 1990.

2.5 The Western Region

2.5.1 Refinery Operations (interpreted within the given scenario)

The new capacity under construction and announced for the region will reduce the need to import finished products such as diesel fuel (which has arisen in the past) modernize the refineries in the area and provide the flexibility required to process heavy oil, tar sands syncrudes and conventional western medium-to-light crudes to the increased volumes of transport fuels and petrochemicals projected.

Thus, while crude volumes run will increase by 9-14% and 12% in 1985 and 1990 over the base year 1979, additions will reduce the utilization of crude processing capacity from 97% levels 80-84% by 1984 and 85-91% of the new capacity by 1990. New vacuum processing units will reach 100% capacity in the high distillate demand case by 1990, when further expansion is indicated.

The gravity of crudes and syncrudes available in the region is expected to degrade (from 38.5 to 34.7 °API), but this is substantially better than

that (29.6 °API) forecast for Quebec by 1990.

In common with all regions except the Atlantic (where Hibernia lightens the crude oil feed to refineries), the changing gravity of crudes processed will increase the relative utilization and total throughput of cracking units.

The current type of crackers in the region will continue to produce olefins which will still use all available olefin alkylation and polymerization units. The new refineries aim to maximize diesel and jet fuel production through hydrocracking of heavy distillates which will therefore not produce a flood of olefins, but increase the yield of LPG and middle distillates. These units will prevent a disastrous reduction in distillate quality attendant upon the increased use of synfuels and heavy oil.

It should be noted, however, that the very severe deterioration of distillate quality which would have attended a sharp increase in the level of syncrude when Alsands and Cold Lake production was added, has now been postponed. This may have an effect upon the configuration of the Shell grassroots refinery in Alberta, which was being designed with syncrude and condensates as the predominant feedstock. This change indicates the need in designing all future refinery expansions to provide the maximum processing flexibility consistent with prudent investment.

2.5.2 Gasoline in the West

The increased volume of gasoline required is achieved, but operations to maximize transport distillates and lower yields of straight-run naphtha obtained from heavy and synthetic crudes necessitates increased use of lead additives to obtain octane values in the leaded regular grade. This is preferred to an increase in reformer severity which would reduce the total yield of liquid products somewhat.

2.5.3 Jet Fuel in the West

The blend of conventional, heavy and synthetic crudes expected in the region's refineries will substantially alter other distillate properties as the aromatic content increases with syncrude additions and higher severity processing both at the cracker steps and coking steps on heavy intermediates and refinery residuals. The changed crudes show up in increased gravity of Jet A and Jet B, reduced smoke points which become marginally acceptable, but improved low temperature flow properties and lower sulphur values. On balance, the quality of jet fuel will be acceptable and somewhat better than that expected in Ontario.

2.5.4 Diesel in the West

The syncrude and heavy oil component of the feed to western refineries, coupled with the large demand for diesel fuel, will have its effect on quality despite the introduction of hydrocrackers in new refineries. The gravity of western diesel is already the highest in Canada - increased demand and increased production from each barrel of a poorer quality crude will be reflected in further increases in gravity (and associated aromaticity), which by 1990 will exceed the upper limit of current specifications. Hand in hand with these changes the cetane values will deteriorate further, producing cold-start ('white smoke'), black-smoke-emission-at-full-power -problems, and engine operations which increase carbon deposits and maintenance requirements.

Western diesel fuel quality and winter supply and performance are already serious problems which may deepen until engine technology and fuel additive technology catch up with the need. The impact of syncrudes lies principally in their adverse effect on fuel ignition in current highway diesel engines, especially at low temperatures, offset by improved cold temperature flow properties.

2.5.5 Fuel Oils in the West

The already small requirement for light fuel oil (compared to the rest of Canada and linked to the availability of natural gas) will shrink further. Problems may arise in the low temperature pourability and the tendency to produce smoke on burning. The viscosity specifications for heavy fuel oil in 1985 can only be met by raising production above demand values, but volumes decrease sharply and viscosity improves by 1990, when the use of syncrudes with no residual component increases in the region's refineries.

2.6 Alternative Scenarios

The pattern of future petroleum product demand and domestic oil production is changing rapidly and scenarios examined by the NEB and Monenco are now of historic interest and of little use for fine tuning of energy and oil policy. (This report has a similarly limited useful life).

The conclusions of the NEB investigation published in 1979 were that average API gravity of Canadian crude (all western at that time) would decrease to provide a heavier crude (37° to 35.4°C, 1978 to 1990), with similar decreases in heavy oil (24 to 23.3° API), and that the sulphur levels would decrease (0.77 to 0.6 weight %). They pointed out that construction of an upgrader facility by 1985 would compensate for the gravity change in the heavy crude stream and also that the distillation characteristic of Canadian crude would change to increase the volume of middle distillates from 35 to 40% of the product, with corresponding reductions in the production of naphtha and residual fuels.

The outcome of the processing of these crudes within a hypothetical Canadian refinery provided 18.4% less diesel fuel and 41.6% less petrochemical feedstocks than required in 1990, while, at the same time, the heavy fuel oil production would be 21% above the 1990 need. In the current investigation, the same impacts apply, but specifications were relaxed and announced refinery additions included to force the volumes of transport

fuels from the crude mix to match the new levels of 1990 demand.

The Monenco investigation of a number of possible 1990 supply/demand scenarios reviewed the following cases:

1. A high demand case.
2. A medium demand case; the base case.
3. A low demand case.
4. A case in which a 10% cut in oil supply was made, the cut falling on imports.
5. Case 2 with a 50% increase in diesel production at the expense of gasoline.
6. Case 2, with replacement of gasoline by a hypothetical wide-boiling material with no cetane, octane, distillation, or gravity impediments.
7. Case 2, with the 1990 gasoline component fixed with the lead-to-unleaded ratio which pertained in 1979 (lead reduction is contrary to refinery oil conservation in this scenario).

The most important conclusions were that in Case 2 the oil supply projected would not meet the national requirement for light products; a 1% deficiency was obtained with an 8% surplus of heavy fuel oil generated. Case 5 (high diesel use) reduced that national shortfall when inter-regional transfers were increased to supply the diesel fuel deficiency of Quebec and the west by trading for gasoline. Use of a broad cut fuel eliminated the national light product deficiency, but only after substantial new investments were made in blending, storage and distribution facilities. Reduction in the use of unleaded gasoline from the 67% level projected for 1990 to 25% did not affect significant oil economy, or improve refinery flexibility, since octane is not a problem at the anticipated leaded/unleaded gasoline sales ratios. (Total lead phase-out, however, would be a major problem, but this was not investigated).

In Case 4, where oil use was cut 10% at the expense of imports, it was found that changes in throughput and severity of operations with inter-regional product transfer could permit maintenance of 100% of diesel fuel

production, essentially 100% of jet fuel and light fuel oil production at the expense of gasoline (88% of requirement met) and heavy fuel oil (76% of requirement met) and petrochemical feedstocks (90% of requirement met). The gasoline shortfall outside Quebec attendant upon the cut in oil use could be concentrated in the leaded regular grade, supply of which would be 80% of the normal demand.

The cases chosen in the present investigation are only indicative of the many alternative oil production and refining strategies which may be selected by industry to meet future demand in their market areas. It is not possible in an overview and short work of this type to present all the vagaries possible, or to argue the implications of each of these variables. Even the impact of major new Canadian oil finds (other than Hibernia) have not been considered, nor has the impact of natural gas supply to the Maritimes been considered. Separate detailed investigations of the impact of these possibilities on regional transport fuel supply and quality may be in order. Another major variable - the effect of a phase-out of lead additives to gasoline - is under active investigation by industry and government.

Yet another major area of change lies in the utilization of alternative non oil-based fuels in the transport sector. A considerable number of economic and technical investigations of this opportunity are underway and a brief look at the possible role of alternatives is therefore in order.

PART 3: ALTERNATIVE FUELS

1. A GENERAL OVER-VIEW

1.1 The Options Available to Close the Oil Supply/Demand Gap in Canada

The gap between domestic oil production and the demand for oil to satisfy the Canadian market for petroleum products can be narrowed by a combination of approaches relevant to transportation.

The production approaches:

1. Increased production of oil where that can be done (Hibernia, tertiary recovery).
2. Production and use of alternative fuels, both naturally occurring (compressed gas, propane) and synthetic (methanol, synthetic hydrocarbons).

The conservation approaches:

3. Substitute gas, electricity, propane for oil, transfer unused oil to transport fuel production - an oil conservation, energy substitution route.
4. Institute deep energy conservation practices, particularly conservation of oil use in vehicles.

The option involving production and use of alternative fuels is briefly addressed to complete this assessment of the quality and supply limits of conventional transportation fuels. The alternative fuels may be subdivided into those which more or less fit the current oil refining and distribution infrastructure (coal liquids and gas-based synthetic crudes): those which can be introduced as a blending component for conventional fuels (alcohols, alcohol derivatives such as MTBE, synthetic gasoline) and those which may by-pass the refinery and be distributed in a new way (propane, compressed and liquid natural gas, pure alcohol fuels, synthetic gasoline, hydrogen

and electricity).

The advent of alternative fuels presents serious problems to Canada's refiners, who have excess capacity available for the refining of oil, a declining market and no zest for the adoption of a pathway which would retire further refining capacity, or require large new investments to process coal syncrudes which are even less tractible than the syncrudes from tar sands, or which require similar sized investments to store and distribute fuels, such as methanol, propane and natural gas, which are substantially incompatible with current transport fuels.

Large new incentives are therefore seen to be necessary to induce oil refiners and petroleum product distributors and retailers to accept alternatives, or to others who may wish to compete with conventional marketers of conventional products that are still based upon subsidized oil.

Given adequate incentives, the alternative fuel industry will emerge in this century. A beginning has been made, but large-scale development, trial and research investigations must precede the breakthrough of alternatives. The plausible forecasts of alternative fuel use given in Table 11 may be reached, given the cooperation of the existing fuel and vehicle industries.

Table 11

SUMMARY OF POTENTIAL ALTERNATIVE TRANSPORT FUELS FOR CANADA

(TRANSPORT FUEL DISPLACED IN YEAR - Thousands m^3)

	PROPANE	ALCOHOL/ GASOLINE BLENDS	ALCOHOLS	CNG	TOTAL (1)	% CANADIAN TRANSPORT FUEL DEMAND
1985	2400-3400	140-270	-	50-130	2590-3800	4.5-6.6
1990	2650-3770	320-650	0-90	150-380	3120-4890	5.2-8.2
1995	3200-4200	600-1300	0-2100	320-795	4120-8395	6.6-13.4
2000	3700-4600	870-1750	0-2750	510-1270	5080-10,370	7.6-15.5

Notes: (1) Thousands of BPD (rounded) of transport fuels displaced:
1985: 45-66 1990: 54-84 1995: 71-155 2000: 88-180
About twice that volume of oil would need to be imported to provide these transport fuels.

(2) Coal syncrudes are not considered to be commercially available in substance before 2000.

Source: R.F. Webb Corporation Ltd.

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APPENDIX 1: STATEMENT OF WORK

TASK II - Assessment of the Quality and Supply Limits of Conventional Transportation Fuels

The contractor will provide a critical review of future changes expected in the supply and quality (related to performance) of conventional transport fuels for Canada, the limits to production and quality associated with anticipated changes in refinery practice and processes, the changing demand for transport fuels (e.g. dieselization effect upon demand for diesel and gasoline), quality of crudes to Canadian refineries (including regional changes), the effect of anticipated changes in legislation relative to fuel economy, allowable (legislated) pollution levels, the availability of alternative fuels and additives and of new engine types.

The main purpose of the study report will be to identify trends and limits. A second purpose will be to review these in the light of certain future levels of transport fuel demand (such as those set in the National Energy Program) and supply of non-conventional fuel alternatives.

The contractor will utilize certain existing studies of refining models (in particular, that developed by Montreal Engineering Ltd.) and fuel analyses (such as Fuel Supply for Diesel Locomotives/Hycarb Engineering Ltd.), but the conclusions and the required report will be based, not only on these studies, but upon others available in the current literature, the company's own fuel databank and from discussions with the industry in Canada. Certain new refinery model runs will be required: these will be defined for execution by selected contractors, such as Montreal Engineering Ltd.

The output of this task is to be an "executive level" report suitable for use within Transport Canada and for issue to planners, managers and others in the Canadian transport community. The "executive level" report is to be supported by working papers as appendices.